FINAL DECISION
Essential Energy distribution determination
2015−16 to 2018−19

Attachment 16 – Alternative control services

April 2015

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Note

This attachment forms part of the AER's final decision on Essential Energy’s revenue proposal 2015–19. It should be read with other parts of the final decision.

The final decision includes the following documents:

Overview

Attachment 1 - Annual revenue requirement

Attachment 2 - Regulatory asset base

Attachment 3 - Rate of return

Attachment 4 - Value of imputation credits

Attachment 5 - Regulatory depreciation

Attachment 6 - Capital expenditure

Attachment 7 - Operating expenditure

Attachment 8 - Corporate income tax

Attachment 9 - Efficiency benefit sharing scheme

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Attachment 13 - Classification of services

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Attachment 18 - Connection methodology

Attachment 19 - Analysis of financial viability

Contents

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
DRP	debt risk premium
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	expenditure forecast assessment Guideline for electricity distribution
F&A	framework and approach
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model

RIN	regulatory information notice
RPP	revenue and pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

16 Alternative control services

Alternative control services are those that are provided by distributors to specific customers. They do not form part of the distribution use of system revenue allowance provide by us to each distributor. Rather, distributors recover the costs of providing alternative control services through a selection of fees, most of which are charged on a ‘user pays’ basis.

This section describes the AER’s determination on the charges that distributors can levy customers for the provision of ancillary network services, public lighting and metering.

16.1 Ancillary network services

Ancillary network services are non-routine services distributors provide to individual customers on an 'as needs' basis.

In the 2009–14 regulatory control period, we classified ancillary network services as standard control services. Essential Energy called these 'miscellaneous' and 'monopoly' services. The Independent Pricing and Regulatory Tribunal (IPART) originally set the fees and labour rates for these services in 1999.[1] The fees have since been indexed by inflation (in 2009 labour escalation was also taken into account).[2]

As we discussed in the stage 1 F&A and confirm in this final decision, we classify ancillary network services as alternative control services.[3]

For the avoidance of doubt, this final decision refers to ancillary network services for which a charge is approved as 'fee-based services'. That is, we determined the fee using the cost of providing the service (labour rates) and the average time to perform the service. These services fees are fixed and apply irrespective of the actual time on-site to perform the service, even if that time varies from the benchmark we consider in this decision.

By contrast, quoted services are once off and specific to a particular customer's request. The cost of these services will depend on the actual time taken to perform the service (rather than the benchmark we consider in this final decision). With the hourly rate set, the longer it takes the distributor to perform the service, the more the customer will pay.[4]

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1 IPART was the state regulator that made distribution determinations prior to economic functions being transferred to the AER on 1 January 2008.

2 AER, *Final decision: New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009, pp. 57-58.

3 AER, *Stage 1 framework and approach paper: Ausgrid, Endeavour Energy and Essential Energy: Transitional regulatory control period 1 July 2014 to 30 June 2015, Subsequent regulatory control period 1 July 2015 to 30 June 2019,* March 2013, p. 32.

4 This is analogous to engaging a plumber to fix drainage problems in a house. The plumber's hourly rate is known in advance but the time taken to perform the fix is variable and will determine the final bill.

16.1.1 Final decision

We do not approve Essential Energy's revised proposed fees for ancillary network services.

Essential Energy's proposed fees are higher than fees based on maximum rates for the distributor's labour types which we consider efficient for providing these services. More detail on our reasoning is in section 16.1.4.

Appendix A contains final decision fees Essential Energy can charge for ancillary network services.

Table 16.24 sets out fees for fee based services and

				Proposed price ($2014-15)			AER final decision ($2014-15)			Difference (per cent)	
INSPECT AND CW RELATED FEES											
ASP inspection L1 - UG urban			Class A	Class B	Class C	Class A	Class B	Class C	Class A	Class B	Class C
	First 10 Lots	/ application	82.87	198.90	414.36	82.87	198.90	414.36	–	–	–
	11-40 Lots	/ application	82.87	116.02	232.04	82.87	116.02	232.04	–	–	–
	Over 40 Lots	/ application	16.57	66.30	111.05	16.57	66.30	111.05	–	–	–
ASP inspection L1 - OH rural											
	1-5 poles	/ application	99.45	198.90	331.49	99.45	198.90	331.49	–	–	–
	6-10 poles	/ application	82.87	165.75	306.63	82.87	165.75	306.63	–	–	–
	11 or more poles	/ application	71.40	116.02	249.89	71.40	116.02	249.89	–	–	–
ASP inspection											

L1 - UG C&I or rural											
	First 10 Lots	/ application	82.87	198.90	414.36	82.87	198.90	414.36	–	–	–
	Next 40 Lots	/ application	82.87	198.90	414.36	82.87	198.90	414.36	–	–	–
	Remainder	/ application	82.87	198.90	414.36	82.87	198.90	414.36	–	–	–
ASP inspection L1 - C&I developments											
	ASP inspection L1 - C&I developments	/ hour		165.75			165.75			–	
ASP inspection L1 - AR or SL											
	ASP inspection L1 - AR or SL	/ hour		165.75			165.75			–	
ASP inspection L2											
	A Grade	/ application		41.44			41.44			–	
	B Grade	/ application		69.62			69.62			–	
	C Grade	/ application		198.89			198.89			–	
ASP reinspection											
	ASP reinspection	/ hour		165.75			165.75			–	
Substation Commissioning - UG Urban											

	Per Lot	/ application	2422.16	2307.73	-4.7
Substation Commissioning - Other					
	Per substation	/ application	2422.16	2307.73	-4.7
Access Permits - UG urban					
	Per Lot	/ application	2608.48	2485.25	-4.7
Access Permits - other					
	Max per access permit	/ application	2608.48	2485.25	-4.7
Admin - UG urban					
	Up to 5 Lots	/ application	424.67	356.22	-16.1
	6-10 Lots	/ application	530.83	445.28	-16.1
	11-40 Lots	/ application	743.17	623.39	-16.1
	Over 40 Lots	/ application	849.34	712.45	-16.1
Admin - OH rural					
	Up to 5 poles	/ application	424.67	356.22	-16.1
	6-10 poles	/ application	530.83	445.28	-16.1
	11 or more poles	/ application	955.50	801.50	-16.1
Admin - other					

Max fee at six hours	/ application	637.00	534.33	-16.1

Table 16.25 sets out labour rates for quoted services.

Form of control

Our final decision is to apply a price cap for the form of control to ancillary network services, consistent with the stage 1 F&A. Figure 16.1 and Figure 16.2 set out the control mechanism formulas for fee based services and quoted services, respectively. They are consistent with the formulas we set out in the draft decision[5] and which Essential Energy agreed in its revised regulatory proposal. [6]

Form of control—fee based services

Under this form of control, we set a schedule of prices for the first year. For the following years the previous year's prices are adjusted by CPI and an X factor.

The form of control for fee based ancillary network services is:

Figure 16.1 Fee based ancillary network services formula

$\bar{p}_i^t \geq p_i^t$ i=1,...,n and t=1, 2, 3, 4

$\bar{p}_i^t = \bar{p}_i^{t-1}(1 + \Delta CPI_t)(1 - X_i^t) + A_i^t$

Where:

$\bar{p}_i^t$ is the cap on the price of service i in year t. For 2015–16 this is the price as determined in appendix A.1, escalated by ∆CPI and the X-factor.

p_i^t is the price of service i in year t.

$$\Delta CPI_t = [\frac{CPI_{Mar,t-2} + CPI_{Jun,t-2} + CPI_{Sep,t-1} + CPI_{Dec,t-1}}{CPI_{Mar,t-3} + CPI_{Jun,t-3} + CPI_{Sep,t-2} + CPI_{Dec,t-2}}] - 1$$

CPI means the all groups index number for the weighted average of eight capital cities as published by the ABS, or if the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best estimate of the index.

X_i^t is the value of X for the year t in the regulatory control period, as Table 16.1 sets out.

5 AER, *Draft decision: Essential Energy distribution determination 2015–16 to 2018–19: Attachment 16: Alternative control services*, November 2014, pp. 13–15.

6 Essential Energy, *Revised regulatory proposal: 1 July 2014 to 30 June 2019*, 20 January 2015, p. 77.

Table 16.1 AER final decision on X factors for each year of the 2015–19 period

	2015–16	2016–17	2017–18	2018–19
X factor	–1.02	–1.07	–1.11	–1.10

Source: AER analysis.

Note: To be clear, labour escalators themselves are positive for each year of the regulatory control period. However, the labour escalators in this table are operating as defacto X factors. Therefore, they are negative.

$\bar{p}_i^1$ is the cap on the price of service i in the first year of the subsequent regulatory control period. See appendix A.1.

A_i^t is an adjustment factor for residual charges when customers choose to replace assets before the end of their economic life. For ancillary network services we consider the value for A is zero.

Form of control—quoted services

Figure 16.2 Quoted services formula

Price = labour + contractor services + materials

Contractor services (including overheads)—reflects all costs associated with the use of external labour in the provision of the service, including overheads and any direct costs incurred as part of performing the service. The contracted services charge applies the rates under existing contractual arrangements. The direct costs incurred as part of performing the service, for example permits for road closures or footpath access, are passed on to the customer. Contractor services are escalated annually by ∆CPI.

Materials (including overheads)—reflects the cost of materials directly incurred in the provision of the service, material storage and logistics on-costs and overheads. Materials are escalated annually by ∆CPI.

Labour is the maximum hourly charge out rate including on-costs and overhead. Labour is escalated annually by $(1 – X_t)(1 + \Delta CPI_t)$.[7]

Table 16.2 sets out the escalation rates for each year that can apply to the labour rates.[8]

Table 16.2 AER final decision on labour escalation factor to apply to maximum labour charge out rates for quoted services

	2015–16	2016–17	2017–18	2018–19

[7] The definition of X and ∆CPI for Figure 16.2 are the same as for Figure 16.1.

[8] Our opex rate of change attachment discusses the escalation factors.

X factor	–1.02	–1.07	–1.11	–1.10

Source: AER analysis.

Note: To be clear, labour escalators themselves are positive for each year of the regulatory control period. However, the labour escalators in this table are operating as defacto X factors. Therefore, they are negative.

16.1.2 Revised proposal

Essential Energy did not revise its ancillary network services prices to reflect the draft decision's labour and overhead benchmarks. Essential Energy stated:

- its labour rates represent cost-reflective and efficient prices based on actual information
- its overheads are in accordance with the approved cost allocation methodology (CAM).[9]

Essential Energy revised its charges to reflect the latest available information and to represent what it considered was a cost-reflective, efficient outcome.[10]

16.1.3 Assessment approach

This final decision continues to adopt the draft decision approach of focussing on the key inputs in determining prices for ancillary network services. We considered:

- Essential Energy’s revised proposal[11]
- Marsden Jacob's analysis of ancillary network services, including recommended maximum total labour rates for Sydney.

As with the draft decision, we consider labour is the key input in determining an efficient level of fees for ancillary network services. We focused on comparing Essential Energy's proposed total labour rates against maximum total labour rates for Sydney that Marsden Jacob developed. In this final decision, 'total labour rates' comprise raw labour rates, on-costs, and overheads.

Our final decision maximum total labour rates apply the following labour components to arrive at a maximum total labour rate (for particular labour types).

- a maximum raw labour rate
- a maximum on-cost rate and

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9 Essential Energy, *Revised regulatory proposal: 1 July 2014 to 30 June 2019*, 20 January 2015, pp. 259–261; Essential Energy, *Revised regulatory proposal: Attachment 9.8: Ancillary network services revised proposal*, 20 January 2015, p. 4.

10 Essential Energy, *Revised regulatory proposal: 1 July 2014 to 30 June 2019*, 20 January 2015, p. 257.

11 Essential Energy, *Revised regulatory proposal: 1 July 2014 to 30 June 2019*, 20 January 2015, p. 257–261; Essential Energy, *Revised regulatory proposal: Attachment 9.8: Ancillary network services revised proposal*, 20 January 2015.

- a maximum overhead rate.

As we explain in more detail in section 16.1.4, Marsden Jacob obtained ranges (that is, minimum rates and maximum rates) for each of these components. Marsden Jacob then applied the maximum from these ranges to derive the maximum total labour rate.[12] We consider that using Marsden Jacob's recommended maximum labour rates to determine appropriate fees for services will provide Essential Energy with a reasonable opportunity to recover at least the efficient costs it incurs in providing these services. It will promote the efficient provision of electricity services and allow a return commensurate with the regulatory and commercial risks involved for the provision of those services.[13]

Where Essential Energy's proposed total labour rates exceeded the maximum total labour rates, we applied our maximum total labour rates to determine ancillary network services charges. Equally, we adopted Essential Energy's proposed total labour rates where they sat below Marsden Jacob's maximum total labour rates.

As a further check of our analysis, we also compared components of Essential Energy's proposed labour costs with those of the Victorian distributors. We consider the latter's costs generally closer to efficient levels.[14]

In coming to conclusions about the fees for Essential Energy's most frequently requested ancillary network services, we also assessed the times taken to perform the service.

In its revised proposal, Essential Energy took issue with our application of labour rates in the draft decision. We have addressed these specific issues in section 16.1.4 of this final decision.

[12] Marsden Jacob, *Final: Provision of advice in relation to Alternative Control Services – Public version: Advice prepared for the Australian Energy Regulator*, 20 October 2014, pp. 1–6.

[13] NEL, s7A and 16

[14] Deloitte Access Economics, *NSW distribution network service providers labour analysis–Addendum to 2014 report*, April 2015.

16.1.4 Reasons for final decision

We do not approve Essential Energy's revised proposed fees for ancillary network services. Proposed fees exceed those based on maximum total labour rates for Essential Energy's labour types which we consider efficient for providing these services. As we set out in section 16.1.3, we compared Essential Energy's total labour rates against Marsden Jacob's maximum (rather than, for example, average) total labour rates. We note ancillary network services comprise a relatively small portion of Essential Energy's revenue. This is because a relatively small number of Essential Energy's customers request ancillary network services in any given regulatory year. Hence we consider it prudent to use maximum total labour rates as an input to derive prices for ancillary network services. Maximum total labour rates act as 'ceilings' on the rates we consider Essential Energy should pay for the various labour types. Where Essential Energy reveals rates lower than the maximum total labour rates, we consider those lower rates should be the inputs for deriving ancillary network services prices. We consider this ensures the distribution business has a reasonable opportunity to recover at least its efficient costs, while also allowing a return commensurate with the regulatory and commercial risks in providing the services.

Our final decision prices are lower than Essential Energy's revised proposal fees for some ancillary network services. However, we have also accepted a large number of Essential Energy's revised proposal fees for ancillary network services (see Table 16.24). Essential Energy revised its labour rates downward compared to its original proposal.[15] Essential Energy's revised proposal labour rates were lower than our maximum total labour rates for technical officers (indoor and outdoor) and field workers. We revised downward only the rates for administration and engineering officers to match our maximum total labour rate (see Table 16.3).[16] This resulted in lower fees in Essential Energy's revised regulatory proposal compared to its original proposal.

Essential Energy stated it does not consider the techniques we used in the draft decision 'are sufficiently refined to be relied upon to such a degree'.[17] Essential Energy did not provide any persuasive evidence or critique of the techniques the draft decision relied upon to substantiate these general statements. As we noted in the draft decision, our main concern is the cost inputs Essential Energy used in its methodologies.[18] We consider Marsden Jacobs used robust methods and inputs to produce its recommended maximum total labour rates, as we set out in detail in the sections below.

15 Essential Energy, *Revised regulatory proposal: Attachment 9.9: Ancillary network services models*, 20 January 2015; Essential Energy, *Regulatory proposal: Attachment 8.9: Ancillary network service models*, 30 May 2014.

16 This is consistent with the method we set out in section 16.1.3.

17 Essential Energy, *Revised regulatory proposal: 1 July 2014 to 30 June 2019*, 20 January 2015, p. 258.

18 AER, *Draft decision: Essential Energy distribution determination 2015–16 to 2018–19: Attachment 16: Alternative control services*, November 2014, p. 18.

Our assessment focussed on the inputs to the methods Essential Energy used to derive its fees for ancillary network services. In particular, labour is the major input to their proposed ancillary network services fees. Essential Energy stated it based its labour rates on actual information and its current enterprise agreement labour rates.[19] Where there are inefficiencies in actual costs, these will be carried through in the derivation of proposed fees. We found proposed labour rates were inefficient. Hence, we adjusted Essential Energy's total labour rates where they exceeded the maximum total labour rates that Marsden Jacob developed and recommended (see section 16.1.3).

Each of the NSW and ACT distributors used different labour category names and descriptions. However, Marsden Jacob found that the types of labour distributors used to deliver ancillary network services broadly fell into one of five categories:

- Administration
- Technical services
- Engineers
- Field workers, and
- Senior engineers.[20]

Table 16.3 shows Essential Energy's proposed total labour rates.[21] Table 16.3 also shows the maximum total labour rates Marsden Jacob developed. We consider these maximum total labour rates should be used to assess Essential Energy's proposed charges for ancillary network services.

Marsden Jacob developed and recommended total maximum labour rates for each of these labour categories. They assessed raw labour rates (see 16.1.4.1), on-costs (see 16.1.4.2), and overheads (see 16.1.4.3) separately and derived maximum rates for each component. Marsden Jacob then applied these maximum rates to produce the maximum total labour rates.

We used these maximum total labour rates to determine whether Essential Energy's proposed fees for ancillary network services reflect the underlying cost of an efficient labour rate. We consider this to be a prudent approach. It provides the distribution business with a reasonable opportunity to recover at least its efficient costs. We consider fees based on labour rates higher than the maximum total labour rates would be inefficient.

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19 Essential Energy, *Revised regulatory proposal: Attachment 9.8: Ancillary network services revised proposal*, 20 January 2015, pp. 4 and 6.

20 Marsden Jacob, *Final: Provision of advice in relation to Alternative Control Services – Public version: Advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 1.

Table 16.3: Essential Energy's proposed total labour rates (including on costs and overheads), and our final decision ($2014–15)

Category	Description	Essential Energy proposed total charge ($2014–15)	AER maximum total labour rates ($2014–15)
Admin	Administration	106.17	89.06
Technical	Indoor technical officer	138.35	142.81
Technical	Outdoor technical officer	165.75	167.96
Engineer	Engineering officer	186.32	177.52
Field worker	Field worker	126.23	133.80

Source: Essential Energy, *Revised regulatory proposal: Attachment 9.9: Ancillary network services models*, January 2015; Marsden Jacob Associates, Email advice to the AER, 1 October 2014.

16.1.4.1 Raw labour rates

In developing maximum raw labour rates (that is, excluding on-costs and overheads), Marsden Jacob examined Hays 2014 salary data. The Hays 2014 salary reports draw on information from 2,500 companies across Australia and New Zealand. Australian distributors in the Hays data (who gave permission to be named) were ActewAGL, Jemena, and CitiPower.[22] The Hays rates draw from a wide pool of labour which Essential Energy would likely have access to. We therefore consider these rates provide a good representation of the competitive market rate for appropriate categories of labour.

Essential Energy maintained it cannot obtain the rates as described in the Marsden Jacob analysis because its labour rates are locked in via an enterprise bargaining agreement.[23] Essential Energy revised its rates for administration labour (R1) downward, but considered its other labour rates were cost reflective.[24]

AGL, in a written submission, queried whether these labour rates are efficient or a current reflection of the NSW labour market. It submitted that the NSW distributors provided no justification as to why local market conditions require much higher labour

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22 A list of contributors to the Hays 2014 salary data who gave permission to be named is available on Hays, *Contributors—Hays 2014 Salary*, accessed 12 February 2015, *Guide* http://www.hays.com.au/salary-guide/HAYS_375078

23 Essential Energy, *Revised regulatory proposal: Attachment 9.8: Ancillary network services revised proposal*, 20 January 2015, p. 6.

24 Essential Energy, *Revised regulatory proposal: Attachment 9.8: Ancillary network services revised proposal*, 20 January 2015, p. 6.

rates than other states. AGL supported our comparison of labour rates and on-costs against other states as an appropriate means of evaluation and analysis.[25]

This echoes the Energy Users Association of Australia's submission not to allow the NSW distributors to effectively treat their negotiated labour rates in enterprise bargaining agreements as 'pass throughs'.[26]

We do not assume that a wage deal struck through an enterprise bargaining agreement is automatically efficient. If the service provider expected us to use the costs revealed through its enterprise bargaining agreement as the starting point for determining total labour expenditure, it would not have an effective incentive for cost control, the efficient provision of services and the efficient use of the distribution system.[27] Effectively, that would make such expenditures akin to cost of service regulation, rather than the NER's emphasis on incentive regulation.

Discussed below, Marsden Jacob developed its recommendations using labour types and their respective rates that are available in a competitive labour market.

Essential Energy stated Marsden Jacob's analysis ignores the fact that it cannot access a national or international labour market.[28] It was not clear to Essential Energy whether the results are driven by lower labour rates in other states, countries or industries.[29]

Marsden Jacob reviewed salary information from all Australian cities. However, it only used Sydney salary data to develop its recommended maximum raw labour rates in respect of the NSW distributors.[30] Marsden Jacob compared labour rates it developed using the Hays Sydney data against the Hays Melbourne data. Marsden Jacob did this as a cross-check to test the reasonableness of its recommended labour rates. Marsden Jacob found its recommended labour rates did not differ significantly from the Hays Melbourne raw labour rate data.

In its report, Marsden Jacob also included raw labour rates across the five labour categories for Brisbane and Auckland. Marsden Jacob included this data for illustration purposes—labour rates in each category did not vary significantly across these locations. The differences observed probably captured differences between locations including economic conditions, labour laws and population. For these reasons, we

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25 AGL, *Submission on NSW distributors draft decisions*, 15 February 2015, p. 4.

26 Energy Users Association of Australia*, Submission to NSW Electricity Distribution Revenue Proposals (2014/15 to 2018/19)*, 8 August 2014, pp. 9–10; Energy Users Association of Australia, *Submission to NSW DNSP revised revenue proposal to AER draft determination (2014 to 2019)*, 13 February 2015, p. 44.

27 NEL ss. 7, 7A and 16; AER, *Final decision: Powerlink transmission determination 2012–13 to 2016–17*, April 2012, p. 52.

28 Labour mobility is well understood in the mining industry. Skilled electricians are also available to any Australian distributor, no matter where that labour resides within Australia.

29 Essential Energy, *Revised regulatory proposal: Attachment 9.8: Ancillary network services revised proposal*, 20 January 2015, p. 5.

30 Marsden Jacob, *MJA analysis.*

consider the Sydney rates alone were acceptable to develop maximum recommended labour rates for ancillary network service charges for the NSW and ACT distributors.

Marsden Jacob used job titles from Hays' energy specific salary guide to develop maximum raw labour rates.[31] Marsden Jacob supplemented this with data from the Hays office support salary guide.[32] This ensured that the 'administration' category was sufficiently covered.

Marsden Jacob analysed 66 different job titles, then used 36 of these to develop rates for the five labour categories.[33] These 36 labour job titles involved tasks which clearly fell into either the 'administration', 'technical specialist', 'engineer', 'field worker', or 'senior engineer' labour categories. Marsden Jacob excluded job titles that were not relevant to electricity distributors such as 'wind farm engineer'. Table 16.4 shows the 36 job titles Marsden Jacob used to develop recommended maximum labour rates for each of the five labour categories. We consider these 36 job titles provide Marsden Jacob with a sample of labour rates available in a competitive labour market.

Table 16.4: Job titles Marsden Jacob used to develop maximum labour rates

Labour category		Job title
Admin	14 data points	Project secretary / Administrator
	(7 job titles)	Client liaison (residential)
		Data entry operator
		Records officer
		Administration assistant (12+ months experience)
		Project administration assistant (3+ years experience)
		Project coordinator
Technical specialist	22 data points	Technician
	(11 job titles)	Control room operator
		Control room manager
		E&I technician
		Protection technician
		Generator technician
		Operator / manager
		Site engineer

31 Hays, *The 2014 Hays salary guide: salary & recruiting trends*, 2014.

32 Hays, *The 2014 Hays salary guide: salary & recruiting trends*, 2014.

33 Marsden Jacob, *MJA analysis.*

		Planner / scheduler
		OHS supervisor
		OHS manager
Engineer	14 data points	Design engineer
	(7 job titles)	Project engineer (EPCM)
		Power systems engineer
		Protection engineer
		Transmission line design engineer
		Asset engineer (3 to 7 years)
		Project engineer
Field worker	14 data points	Leading hand
	(7 job titles)	Electrician
		Mechanical fitter
		Line worker
		G&B lines worker
		Cable jointer
		Cable layer
Senior engineer	8 data points	Senior design engineer
	(4 job titles)	Principal design engineer
		Senior project engineer (EPCM)
		Commissioning Engineer

Source: Marsden Jacob analysis

Marsden Jacob considered the range of data provided for each labour category across the various job titles. In doing this, it derived salary ranges for each labour category by:

- identifying the lowest salary from all job titles in the labour category
- identifying the highest salary from all job titles in the labour category.

We consider this range represents the full pool of labour (and raw labour rates) that Essential Energy would have access to in a competitive labour market. Marsden Jacob recommended using the maximum raw labour rate for each labour category to develop its maximum total labour rate.[34] We consider this to be a prudent approach. It provides

[34] Marsden Jacob, *Final: Provision of advice in relation to Alternative Control Services – Public version: Advice prepared for the Australian Energy Regulator*, 20 October 2014, pp. 2–3.

the distribution business with a reasonable opportunity to recover at least its efficient costs, while promoting the efficient provision of services.

Table 16.5: Marsden Jacob maximum raw labour rates

Marsden Jacob labour category	AER maximum raw labour rate ($2014–15)
Admin	39.00
Technical	59.00
Engineer	69.00
Field worker	47.00
Senior engineer	82.00

Source: Marsden Jacob, *Final: Provision of advice in relation to Alternative Control Services – Public version: Advice prepared for the Australian Energy Regulator*, 20 October 2014, pp. 2–3.

16.1.4.2 On-costs

Marsden Jacob recommended a maximum on-cost rate of 52.23 per cent. Marsden Jacob developed a 'bottom up' estimate of on-costs for the NSW and ACT distributors. Marsden Jacob did this for each of these businesses with reference to the following factors:

- the superannuation levels included in each distributor's enterprise bargaining agreement
- a conservative estimate of workers compensation premium
- standard payroll tax rates in NSW and the ACT
- annual leave loading of 17.5 per cent loading on four weeks annual leave, which equates to 1.35 per cent of total salary.
- a conservative long service leave allowance based on three months leave for every ten years of service, equating to 2.5 per cent per year.
- an assumed rate of 18.18 per cent standard leave (including annual leave, sick leave, and public holidays) for all businesses.

Based on these factors, Marsden Jacob calculated a maximum on-cost rate for the ACT and NSW businesses of 52.23 per cent.[35] It then used this maximum on-cost rate to derive its maximum total labour rates. We consider this to be a prudent approach that is consistent with the revenue and pricing principles.

Essential Energy stated it applies on-costs only to productive hours (that is, hours worked, excluding leave). Essential Energy outlined that this results in a higher on-cost

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[35] Marsden Jacob, *Final: Provision of advice in relation to Alternative Control Services – Public version: Advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 4.

rate compared to the Marsden Jacob rates, which follows a bottom-up estimate applied to all paid hours. For example, applying the 15 per cent superannuation rate to 82 per cent productive time (42.6 weeks per annum) results in an 18.4 per cent on-cost contribution. Essential Energy recommended we apply its on-cost rates to enable full cost recovery of labour related entitlements.[36]

Marsden Jacob derived total on-cost rates by compounding rates for basic leave entitlements and various standard on-costs such as superannuation and payroll tax.[37] This method takes account of productive hours throughout the calculations (implicit in the compounding calculation). This is mathematically equivalent to a 'gross up' approach where individual elements are 'grossed up' to account for productive hours (and each of the other on-costs in turn). These elements are then added together to derive the overall on-cost rate (rather than compounding these values).

Marsden Jacob's assumptions for productive time was similar to that used by Essential Energy (42.70 weeks per annum) and results in a 'grossed up' superannuation rate of 18.2 per cent.

Essential Energy's method of applying on-costs only to productive time does result in higher rates for individual on-cost items. However, by 'grossing up' these values initially, the appropriate method to derive an overall on-cost rate is to sum these individual rates (rather than to compound these values). Summing up these individual rates would result in an overall on-cost rate that is lower than Marsden Jacob's recommended maximum of 52.23 per cent.[38]

In its revised regulatory proposal, Essential Energy did not provide other information that would justify on-cost rates above 52.23 per cent. For example, Essential Energy did not describe other on-costs Marsden Jacobs may not have considered in its report.[39] Essential Energy also did not provide any additional information that would indicate a different method to the compounding and 'grossing up' methods we described above.

16.1.4.3 Overheads

Marsden Jacob applied the maximum overhead rates in Table 16.6 to derive its total labour rates.[40] In recommending these maximum overhead rates, Marsden Jacob compared the overhead rates the NSW and ACT distributors proposed (in their original

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36 Essential Energy, *Revised regulatory proposal: Attachment 9.8: Ancillary network services revised proposal*, 20 January 2015, p. 6.

37 Marsden Jacob Associates, *Final: Provision of advice in relation to Alternative Control Services – Public version: Advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 4.

38 Marsden Jacob Associates, Email to AER, 19 March 2015; Marsden Jacob Associates, Email to AER, 24 March 2015.

39 See table 2 in Marsden Jacob Associates, *Final: Provision of advice in relation to Alternative Control Services – Public version: Advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 4.

40 Marsden Jacob Associates, *Provision of advice in relation to alternative control services—advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 5.

regulatory proposals). Marsden Jacob found that Ausgrid and Endeavour Energy's overhead rates were significantly higher than those of Essential Energy, and ActewAGL. They were also significantly higher than the Victorian distributors' overhead rates.[41] Marsden Jacob therefore recommended maximum overhead rates based on the maximum of only ActewAGL and Essential Energy's proposed overhead rates. Marsden Jacob's maximum overhead rates are also higher than the rates proposed by the Queensland distributors.[42] This adds further support to using Marsden Jacobs' maximum overhead rates to calculate maximum total labour rates. We therefore consider that Marsden Jacob's total labour rates, which use the overhead rates in Table 16.6 as inputs, are prudent and appropriately reflect the revenue and pricing principles.

Table 16.6 Maximum overhead rates

Labour type	Maximum overhead rates (per cent)
Administration	50.0
Technical specialist	59.0
Engineer	69.0
Field Worker	87.0
Senior Engineer	69.0
Average overheads	65.00

Source: Marsden Jacob Associates, *Final: Provision of advice in relation to Alternative Control Services – Public version: Advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 5.

In its discussion of maximum overhead rates, Marsden Jacob noted:

- the nature of the differences in overhead rates may be due to differences in cost allocation methods.
- capping the overhead rate may have unintended consequences for the broader cost allocation methodology.
- we should test the method of addressing overhead allocation vis a vis the cost allocation method.[43]

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41 Marsden Jacob Associates, *Provision of advice in relation to alternative control services—advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 5.

42 Ergon Energy, *Regulatory proposal 2015-20: 05.06.02—fixed fee services model*, 31 October 2014 (CONFIDENTIAL); Ergon Energy, *Regulatory proposal 2015-20: 05.06.03—quoted price services model*, 31 October 2014 (CONFIDENTIAL); Energex, *Regulatory proposal 2015-20: Alternative control services costing model*, 31 October 2014 (CONFIDENTIAL).

43 Marsden Jacob Associates, *Provision of advice in relation to alternative control services—advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 5.

Essential Energy highlighted this in its revised proposal and also submitted that using Marsden Jacobs' overhead rates would result in over-recovery of overheads in most labour categories.[44] As we discussed in section 16.1.4, however, we assessed Essential Energy's total labour rates against Marsden Jacobs' total labour rates. We did not compare the individual components of total labour (raw labour, on-costs and overheads). The grand total, not the sum of its individual parts, was our method for determining labour rates.

Essential Energy also noted Marsden Jacob's method of calculating implied overhead rates results in a different overhead rate for each labour category. This is not consistent with the application of Essential Energy's cost allocation method, which results in a constant overhead rate for all labour categories.[45]

We reviewed the objectives of our cost allocation guideline. The cost allocation method sets out the principles and policies for attributing costs to, or allocating costs between, the categories of distribution services a distributor provides. Hence, in approving a distributor’s cost allocation method, we approve the methodology it uses to allocate costs. This does not equate to approving the costs. The approval of actual costs is subject to applicable requirements set out in the National Electricity Rules and the National Electricity Law.[46] Proper application of the cost allocation method does not indicate whether the distributor's expenditure, including overheads, is at efficient levels or otherwise reflects the requirements of the NER, having regard to the revenue and pricing principles and the national electricity objective.[47] By extension, proper application of the cost allocation method does not indicate whether the resulting overhead rates represent efficient levels.

16.1.4.4 Inconsistencies

Essential Energy provided examples where our application of Marsden Jacob's recommendations resulted in unreasonable outcomes in ancillary network services prices.[48]

Draft decision charge inconsistent with model

Essential Energy noted inconsistencies in the disconnection/reconnection charges we included in our draft decision and in the models we provided to Essential Energy supporting that decision.[49]

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44 Essential Energy, *Revised regulatory proposal: Attachment 9.8: Ancillary network services revised proposal*, 20 January 2015, , p. 7.

45 Essential Energy, *Revised regulatory proposal: Attachment 9.8: Ancillary network services revised proposal*, 20 January 2015, p. 7.

46 AER, *Electricity distribution network service providers—Cost allocation guidelines*, June 2008, p. 7-11.

47 AER, *Electricity distribution network service providers—Cost allocation guidelines*, June 2008, p. 7-11.

48 Essential Energy, *Revised regulatory proposal to the Australian Energy Regulator: Delivering better value: 1 July 2014 – 30 June 2019*, 20 January 2015, p. 246.

49 Essential Energy, *Revised regulatory proposal: Attachment 9.8: Ancillary network services revised proposal*, 20 January 2015, pp. 7–8.

We confirm Essential Energy's statement that the figures we included in table 16.25 of the draft decision were from Marsden Jacob.[50] This explains the slight difference between the charges that Essential Energy identified in its revised proposal.

This final decision accepts Essential Energy's disconnection/reconnection fees proposed in its revised proposal, so this inconsistency no longer exists (see Table 16.24).

Origin submitted it understands Essential Energy combined re-energisation and de-energisation activities within the same fee. A number of submissions highlighted the inequity of this arrangement. Origin did not consider we provided a sufficiently clear explanation of how we assessed the concerns raised by stakeholders.[51] We noted in the draft decision that:

> Essential Energy submitted that part of this fee is a prepayment. The fee is charged at the point of disconnection – it is not charged at the point of reconnection. This fee is intended to cover the costs of disconnecting a customer for a short time period. For example, people who own a vacant holiday home may want to avoid a service availability charge. Essential Energy submitted that this fee would not be used for move-in/move-out situations.[52]

We note Essential Energy's proposed prices are higher than disconnection fees of the Victorian distributors. However, disconnection fees in Victoria are lower because most residential customers have smart meters and disconnections can be done remotely. This is not the case in NSW where smart meters do not exist for all households. Essential Energy's proposed disconnection/reconnection fees are consistent with those of the Tasmanian and Queensland distributors.[53] Like NSW, the Tasmanian and Queensland distributors have not rolled out smart meters to the same extent as in Victoria.

Non-labour direct costs

Essential Energy stated we updated formula source references within its 'ASP fees' model to only include labour costs in the calculation of ASP fees. Essential Energy stated we should not exclude non-labour costs associated with training venue hire and training materials as they are a true cost in providing the services associated with ASP fees.[54]

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[50] Essential Energy, *Revised regulatory proposal: Attachment 9.8: Ancillary network services revised proposal*, 20 January 2015, p. 8.

[51] Origin, *Submission to AER draft determination for NSW electricity distributors*, 13 February 2015, p. 27.

[52] AER, *Draft decision: Essential Energy distribution determination 2015–16 to 2018–19: Attachment 16: Alternative control services*, November 2014, p. 28.

[53] In 2014–15, for example, Aurora charged a disconnection fee of $53.77. Energex charged $54.93 and $70.30 (for site visit), while Ergon charged a disconnection fee for short rural of $102.24 and $592.66 for long rural.

[54] Essential Energy, *Revised regulatory proposal: Attachment 9.8: Ancillary network services revised proposal*, 20 January 2015, p. 8.

We agree with Essential Energy and we have amended our approach to assessing (and amending) the ASP fees such that we include these non-labour costs. Table 16.7 shows we have reduced Essential Energy's ASP fees in this final decision. However, the percentage decrease is not as large as in the draft decision. This is partly due to our inclusion of non-labour costs in our calculation of ASP fees.

Table 16.7 Final decision for Essential Energy ASP fees ($2013–14)

Service	Unit	Revised proposal charge	Final decision	Variation (per cent)
Initial authorisation	per authorisation	761.34	628.98	-17.39
Authorisation renewal	per authorisation	364.41	291.22	-20.08
Authorisation training	per authorisation	285.14	259.86	-8.87
Remedial action of ASPs	per hour	166.03	159.75	-3.78

Source: AER analysis; Essential Energy, *Revised regulatory proposal: Attachment 9.9: ANS_ASP fees*, January 2015.

Partial approval of fees

Essential Energy noted our draft decision reduced fees for class B ASP inspections by 5.4 per cent, but accepted Essential Energy's proposed fees for classes A and C ASP inspections. The reasons for this partial approval of fees was not clear to Essential Energy as all ASP inspection fees (classes A, B and C) all use the same labour category.[55]

This final decision accepts Essential Energy's revised proposal ASP inspection fees for classes A, B and C, so this partial approval of fees no longer exists (see Table 16.24).

Quoted services

Essential Energy included a number of quoted ancillary network services in its original and revised proposals.[56] Essential Energy stated the draft decision provided for some of these charges to on a 'per hour' or 'per application' basis (see Table 16.8). Essential Energy stated it is not clear whether services on a 'per application' basis allow for a quoted service. Essential Energy suggested we clearly identify items that are quoted services.

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55 Essential Energy, *Revised regulatory proposal: Attachment 9.8: Ancillary network services revised proposal*, 20 January 2015, pp. 8–9.

56 Essential Energy, *Revised regulatory proposal: Attachment 9.10: Charges for ancillary network services*, 20 January 2015, p. 3; Essential Energy, *Regulatory proposal: Attachment 8.10: Charges for ancillary network services*, May 2014, p. 3.

Our draft decision was based on the models appended to Essential Energy's original proposal.[57] The models in Essential Energy's revised proposal contained bases that were consistent with its original proposal's models.[58] Hence, there was an inconsistency between its models and its original and revised proposal documents.[59] Essential Energy confirmed that the basis in its revised regulatory proposal is correct.[60]

Table 16.24 of this final decision more clearly indicates that the services in Table 16.8 are quoted services and contain bases consistent with Essential Energy's revised regulatory proposal.

Table 16.8 Services to be provided by quotation

Service	Basis (Essential Energy)	Basis (Draft decision)
High load escorts	per job	per hour
Retailer of last resort	per event	per application
CT meter install	per install	per application
Rectification works - general		per hour

Source: Essential Energy, *Revised regulatory proposal: Attachment 9.8: Ancillary network services revised proposal*, 20 January 2015, p. 9.

Fee based unit change in draft decision

Essential Energy stated the fee structure in the draft decision for 'Design certification–Underground commercial and industrial or rural subdivisions (vacant lots–no development)' differed from the original proposal. Essential Energy proposed to apply this fee on a per lot basis. However, the draft decision applied the fee on a per pole basis. Essential Energy expected this was an error in populating the table within the draft decision and requested that the final decision correct this oversight.[61]

Our draft decision used the basis Essential Energy set out in the model attached to its original proposal.[62] The models in Essential Energy's revised proposal contained bases that were consistent with its original proposal.[63] Hence, there was an inconsistency

[57] Essential Energy, *Regulatory proposal: Attachment 8.9_08: Office fees*, May 2014; Essential Energy, *Regulatory proposal: Attachment 8.9_09: Field services fees*, May 2014.

[58] Essential Energy, *Revised regulatory proposal: Attachment 9.9: ANS_Office fees*, 20 January 2015; Essential Energy, *Revised regulatory proposal: Attachment 9.9: ANS_Field services fees*, 20 January 2015.

[59] Essential Energy, *Regulatory proposal: Attachment 8.10: Charges for ancillary network services*, May 2014, p. 3; Essential Energy, *Regulatory proposal: Attachment 8.9_08: Office fees*, May 2014; Essential Energy, *Regulatory proposal: Attachment 8.9_09: Field services fees*, May 2014.

[60] Essential Energy, *Response: AER reference no: AER Essential 058*, 10 April 2015, p. 1.

[61] Essential Energy, *Revised regulatory proposal: Attachment 9.8: Ancillary network services revised proposal*, 20 January 2015, p. 9.

[62] Essential Energy, *Regulatory proposal: Attachment 8.9_01: Design fees*, May 2014.

[63] Essential Energy, *Revised regulatory proposal: Attachment 9.9: ANS_Design fees*, 20 January 2015.

between its models and its original and revised proposal documents.[64] Essential Energy confirmed that it proposed charging for these design services on a per lot basis.[65]

Table 16.24 of this final decision sets out the fee structure for this service on a per lot basis as Essential Energy advised.

Network tariff change requests

Essential Energy noted we did not approve the 'network tariff change–invalid request' charge. On the other hand we included a 'network tariff change' fee in the draft decision.[66] In response to the draft decision, Essential Energy revised its definition for this service. The fee will now only apply to a valid network tariff change request outside of the annual pricing proposal process. Essential Energy will not apply the fee where a retailer requests a tariff change that cannot be applied, or where Essential Energy incorrectly applied a tariff to the account.[67]

We maintain our draft decision to not adopt a charge for 'network tariff change requests'. This applies whether it is a valid or invalid request. We agree with AGL that this function sits with the distributor and customers should not be charged because the distributor has not placed a customer on the correct network tariff.[68] Origin reiterated these points and supported our draft decision in its submission.[69]

Site establishment fee

Table 16.24 sets out our final decision for Essential Energy's site establishment fee.

Essential Energy stated it currently levies the site establishment fee against the accredited service provider. Essential Energy is considering whether that approach should change. An MSATS system change was implemented in May 2014, with NMIs not published to MSATS until approved by the retailer. In its revised regulatory proposal, Essential Energy proposed levying the site establishment fee against the retailer, subject to Essential Energy's business processes. This is because the retailer must submit an 'Allocate NMI B2B service order'. Essential Energy stated it will

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[64] Essential Energy, *Regulatory proposal: Attachment 8.10: Charges for ancillary network services*, May 2014, p. 3; Essential Energy, *Regulatory proposal: Attachment 8.9_08: Office fees*, May 2014; Essential Energy, *Regulatory proposal: Attachment 8.9_09: Field services fees*, May 2014.

[65] Essential Energy, *Response: AER reference no: AER Essential 058*, 10 April 2015, p. 2.

[66] Essential Energy, *Revised regulatory proposal: Attachment 9.8: Ancillary network services revised proposal*, 20 January 2015, p. 9.

[67] Essential Energy, *Revised regulatory proposal: Attachment 9.8: Ancillary network services revised proposal*, 20 January 2015, p. 10.

[68] AGL, *NSW electricity distribution networks regulatory proposals: 2014- 19: AGL submission to the Australian Energy Regulator*, 8 August 2014, p. 32.

[69] Origin, *Submission to AER draft determination for NSW electricity distributors*, 13 February 2015, p. 27.

consider this potential change further, including consultation with stakeholders, before it makes a final decision.[70]

We note Essential Energy's intention to investigate whether it should levy the site establishment fee against the accredited service provider or the retailer. We consider the outcome should be in accordance with the requirement of the NER.

16.2 Public Lighting

16.2.1 Final decision

We do not approve Essential Energy's proposed public lighting charges. This is mostly on account of us determining a real pre-tax WACC of 4.73 per cent instead of the proposed 7.09 per cent.

We approve the revised proposal in relation to:

- failure rates for calculating operating expenditure
- a three/four year hybrid lamp bulk replacement cycle
- divisional and corporate overhead/indirect cost percentages

We have applied updated labour escalators using the methodology adopted in our draft decision.

We accept all other elements of the distributor's revised proposal public lighting charges.

Form of control

Our final decision is to apply a price cap for the form of control to public lighting, consistent with the stage 1 F&A. Figure 16.3 sets out the control mechanism formulas for public lighting.

Figure 16.3 Public lighting formula

$\bar{p}_i^t \geq p_i^t$ i=1,...,n and t=1, 2, 3, 4

$\bar{p}_i^t = \bar{p}_i^{t-1}(1 + \Delta CPI_t)\left(1 - X_i^t\right) + A_i^t$

Where:

$\bar{p}_i^t$ is the cap on the price of service i in year t. However, for 2015–16 this is the price as determined in appendix A.2.

p_i^t is the price of service i in year t.

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[70] Essential Energy, *Revised regulatory proposal: Attachment 9.8: Ancillary network services revised proposal*, 20 January 2015, p. 10.

$$\Delta CPI_t = [\frac{CPI_{Mar,t-2} + CPI_{Jun,t-2} + CPI_{Sep,t-1} + CPI_{Dec,t-1}}{CPI_{Mar,t-3} + CPI_{Jun,t-3} + CPI_{Sep,t-2} + CPI_{Dec,t-2}}] - 1$$

CPI means the all groups index number for the weighted average of eight capital cities as published by the ABS, or if the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best estimate of the index.

X_i^t is the value of X for the year t in the regulatory control period. There are no X-factors for public lighting

A_i^t is an adjustment factor likely to include, but not limited to, adjustments for residual charges when customers choose to replace assets before the end of their economic life. For public lighting we consider the value for A is zero.

16.2.2 Essential Energy's revised proposal

In its revised proposal, Essential Energy accepted the draft decision methodology for calculating labour escalation.

Essential Energy did not accept the AER's draft decision WACC and instead proposed a real pre-tax WACC of 7.09.

With respect to corporate and divisional overheads, the revised proposal sought a reduction from the initial proposal as set out in Table 16.9. While the proposed overhead rate was reduced, Essential Energy rejected the benchmarking undertaken by the AER for the draft decision and submitted that there are legitimate reasons for overheads varying among different distribution businesses.

Table 16.9 Corporate and Divisional Overheads, per cent

	2015—16	2016—17	2017—18	2018—19
Initial Proposal	41.24	41.36	42.28	42.59
Revised Proposal	37.27	36.17	34.37	34.14

Source: Essential Energy, Initial and revised proposal tariff models.

Essential Energy proposed that their bulk replacement program move from a three to a three/four year hybrid bulk replacement program. Lamps that are not compliant with four year replacement would be progressively replaced where possible in moving to this new program. See proposed replacement frequency set out in Table 16.10.

Table 16.10 Bulk lamps replacement frequency

	4 years	3 years
Compact Fluorescent	55,274	
High Pressure Sodium	66,151	
Low Pressure Sodium		912
Mercury Vapour		20,536

Source: Essential Energy, Revised Proposal, Attachment 9.1 Response to AER Draft Determination on Public Lighting, January 2015, p. 9.

Essential Energy proposed increasing the lamp spot failure rate to account for less frequent replacement and that the operating expenditure model should take account of all components that fail, not just the lamp. Their revised failure rates are set out in Table 16.11.

Table 16.11 Failure Rates, per cent

	Initial Proposal	Revised Proposal
Compact Fluorescent	7.7	8.53
High Pressure Sodium	9.55	10.88
Low Pressure Sodium	10.76	10.76
Mercury Vapour	4.47	4.47

Source: Essential Energy initial and revised proposal operating expenditure models.

16.2.3 AER's assessment approach

The AER has continued with the assessment approach used in the draft decision.[71]

16.2.4 Reasons for final decision

The reasons for the real pre-tax WACC of 4.73 per cent instead of the proposed 7.09 per cent are discussed in full in Rate of Return, Attachment 3.

[71] Essential Energy draft decision 2015–16 to 2018–19: Attachment 16: Alternative control services, November 2014, pp.53-54.

We accept the reduced corporate and divisional overheads in Essential Energy's revised proposal. In the draft decision we benchmarked costs against other distributors and set Essential Energy's overhead rate at 25 per cent.

We accept the revised proposal argument that there are legitimate reasons for overheads varying across businesses in relation to public lighting and we do not consider our benchmarking is sufficiently robust to adjust overheads for this purpose.

The lower percentage overheads applied to the direct costs set out in this final decision result in a significant reduction in the quantum of corporate and divisional overheads, as set out in Table 16.12.

Table 16.12 Corporate and Divisional Overheads, millions

	2015—16	2016—17	2017—18	2018—19
Initial Proposal	4.4	4.5	4.7	4.9
Revised Proposal	3.6	3.6	3.5	3.5
Final decision	3.0	3.4	3.8	4.3

Source: AER analysis.

The draft decision set a four year bulk replacement benchmark for all lamps. We now accept however that a move to a three/four year bulk replacement of lamps is more efficient for Essential Energy. As a transitional measure, it results in a more efficient provision of services, more efficient use of the distribution system and encourages efficient investment in the system. At the same time, progressive replacement of lamps not compliant with lighting standards if replaced on a four year replacement cycle will allow a move to four year bulk replacement program as called for by councils. This will produce cost saving for councils.

Typically with public lighting assets—indeed any assets of a capital nature—less frequent replacement tends to result in a higher incidence of component failure. With lamps replaced less frequently we accept the proposed rise in the failure rate to account for this and that luminaire components that fail need to be accounted for in operating expenditure. Otherwise, the distributor risks not being able to recover the efficient costs of providing the service.

We consider the draft decision was deficient in that it did not take account of all components that fail other than the lamps.[72] This is why the failures rates in this final decision are higher.

[72] The failures cited are; lamp mortality, fuses, ballasts, PE cells, diffusers, wiring faults, master control point failures, lumen depreciation and theft and vandalism. See Essential Energy, Revised Proposal, Attachment 9.1 Response to AER Draft Determination on Public Lighting, p. 11.

We tested Essential Energy's revised proposal failure rates. The best comparator is other distributors providing public lighting services in the national electricity market, particularly those in New South Wales. On this score, the failure rates evidenced by Essential Energy are consistent with Endeavour Energy and compare favourably with those of Ausgrid. On this basis, we have approved them. The final decision failure rates are set out in Table 16.13.

Table 16.13 Failure Rates, per cent

	Draft Decision	Final Decision
Compact Fluorescent	6.0	8.53
High Pressure Sodium	5.0	10.88
Low Pressure Sodium	6.0	10.76
Mercury Vapour	4.0	4.47

Source: AER analysis.

Labour escalators have been updated from the draft decision and are set out in Table 16.14 . The reasons for the final decision labour rates are discussed in opex, attachment 7.

Table 16.14 NSW Labour Escalators, per cent

	2013—14	2014—15	2015—16	2016—17	2017—18	2018—19
Draft Decision	0.58	0.89	0.87	1.40	1.62	1.44
Final Decision	na	1.34	1.02	1.07	1.11	1.10

Source: AER analysis.

Essential Energy has accepted the view from councils that they would prefer the increase in prices to be spread over a number of years rather than a large step up in the 2015-16 year.[73] We agree. The final decision results in Essential Energy's revenue increasing by 13 per cent in 2015—16, compared to 40 per cent sought in the revised proposal and 60 per cent in the initial proposal.

The transition will be net present value neutral with increases in public lighting charges being phased in over the remaining 4 years of the regulatory period, with increases applied in equal increments. All else being equal, the 2021–26 regulatory period would see a reduction in street lighting charges, due to the final year revenue likely being

[73] Essential Energy, Revised Proposal, Attachment 9.1 Response to AER Draft Determination on Public Lighting, p. 3.

above efficient costs due to the NPV phasing. Final decision revenue is set out in Table 16.15.

Table 16.15 Total revenue, $ millions

	2015—16	2016—17	2017—18	2018—19
Initial Proposal	14.9	15.4	15.9	16.5
Revised Proposal	13.3	13.5	13.7	13.9
Final decision	11.1	12.5	14.1	15.9
change from previous year (percentage)	13	13	13	13

Source: AER analysis.

Final decision prices for each light type are set out in appendix X.

16.3 Metering

Our final decision on Essential Energy's metering proposal is made in the context of ongoing policy reform. We based our assessment on the National Electricity Rules (NER) in place at the time of this final decision, but have had regard to the likelihood of policy reform in the future through rule changes that will apply during this regulatory period.

Currently, competition in metering is limited to large customers in the national electricity market while regulated distributors have the sole responsibility to provide small customers with metering services.[74]

The Australian Energy Market Commission (AEMC) is undertaking a rule change process to expand competition in metering and related services to help facilitate a market led roll out of advanced metering technology, following proposals from the COAG Energy Council. The increased availability of advanced meters will enable the introduction of more cost reflective network prices and allow consumers to make more informed decisions about how they want to use energy services.

The AEMC published its draft rule on 26 March 2015. It provides that the AER should determine 'the arrangements for a DNSP to recover the residual costs of its regulated metering service in accordance with the existing regulatory framework'.[75] Other key features of the draft rule change include:

[74] NER clause 7.2.3(a). Small customers refers to any customer with less than 160MWh annual consumption (effectively all residential and small business customers fall into this category).

[75] AEMC, *Draft rule determination: Expanding competition in metering and related services,* 26 March 2015, p. 225.

- the transfer of the role and responsibilities of the existing 'Responsible Person' to a new type of Registered Participant called a Metering Coordinator
- allowing any person to become a Metering Coordinator, subject to meeting the registration requirements
- permitting a large customer to appoint its own Metering Coordinator
- requiring a retailer to appoint the Metering Coordinator, except where a large customer has appointed its own Metering Coordinator.[76]

Our final decision takes the AEMC's draft rule into account and establishes a regulatory framework for the 2015–19 regulatory control period which will be robust enough to handle the transition to competition once the rule change takes effect from 1 July 2017.[77] This involves having transparent standalone prices for all new or upgraded meter connections and annual charges.

The key issue in the lead up to competition is how to recover the residual metering capital costs that arises when metering customers begin to switch to competitive metering providers. Rather than an upfront exit fee which would create a regulatory barrier to competitive entry, our final decision is that switching customers continue to pay the capital cost component of the regulated annual metering service charge.

16.3.1 Final decision

16.3.1.1 Structure of metering charges

We classify type 5 and 6 metering services as alternative control services. The control mechanism for alternative control metering services will be caps on the prices of individual services.

Our final decision approves two types of metering service charges:

- Upfront capital charge (for all new and upgraded meters installed from 1 July 2015)
- Annual charge comprising of two components:
    - capital—metering asset base (MAB) recovery
    - non-capital—operating expenditure and tax.

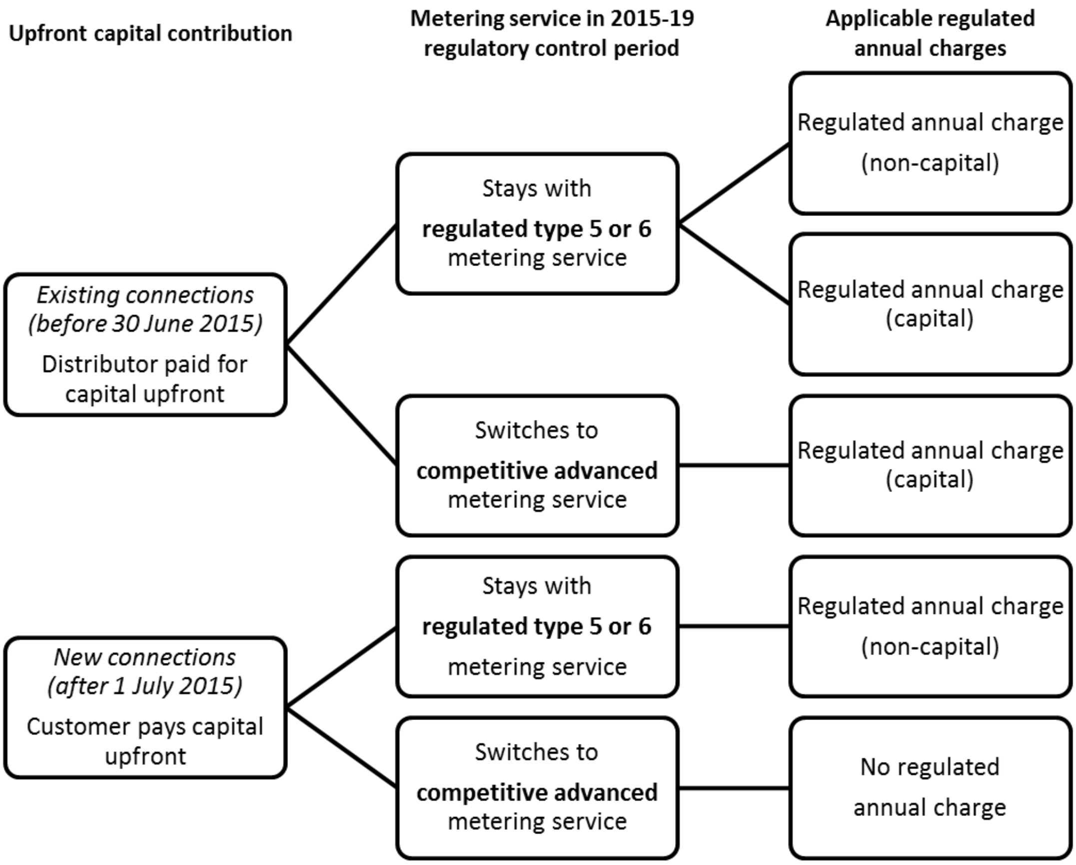
We have not approved a meter transfer fee relating to administrative costs associated with metering customers who switch to a competitive metering provider.

Figure 16.4 depicts how the two regulated annual charge components relate to different metering customers.

[76] AEMC, *Draft rule determination: Expanding competition in metering and related services,* 26 March 2015, p. iii.

[77] AEMC, *Draft rule determination: Expanding competition in metering and related services,* 26 March 2015, p. 79.

Figure 16.4 – final decision – applicable regulated annual charges



Source: AER analysis.

Note: This diagram shows regulated annual charges only. In addition, customers who switch may incur charges for their competitive advanced metering service. Any such charges are not subject to AER oversight and are not shown in the diagram above.

Existing connections (before 30 June 2015)

For regulated meters installed before 30 June 2015, metering capital costs were amortised. That is, distributors paid upfront for the capital costs which were then added to the asset base and recovered gradually through annual charges.

If a customer with an existing regulated metering connection on their premises receives a regulated type 5 or 6 metering service, they pay the following charges:

- Capital (MAB recovery[78]) component of regulated annual metering charge
- Non-capital (opex and tax) component of the regulated annual metering charge

[78] The MAB is largely the undepreciated value of all existing meters. It will increase slightly in the 2015–19 regulatory control period to include forecast replacement capex. A meter has to be replaced if it suddenly fails or may have to be proactively replaced because the distributor must comply with AEMO's metrology procedures.

If a customer with an existing regulated metering connection on their premises chooses to switch to a competitive advanced metering service (and no longer receives a regulated type 5 or 6 metering service) they stop paying the non-capital component of the regulated annual metering charge. They will pay the following charges:

- Capital component of the regulated annual metering charge.
- This charge recovers the MAB from all customers with existing connections (from before 30 June 2015) on their premises, whether or not they subsequently switch from their existing regulated meter to an advanced meter. As a result, the diminishing number of customers who remain with their existing regulated meters are not required to pay the entire capital cost of the MAB. This has the benefit of minimising cross subsidies between customers switching to competitive meters and those remaining on regulated meters. It also means the contribution towards the recovery of the metering asset base is relatively small because it is paid through ongoing annual charges rather than an upfront exit fee.
- Any charges payable to their competitive metering provider for advanced metering services. Any such charges are not subject to AER oversight and are not shown in Figure 16.4.

This structure applies even if a customer pays upfront for a meter upgrade to their existing regulated meter after 1 July 2015 (for example, wants to upgrade from a type 6 to a type 5 meter) and then switches to a competitive advanced metering provider. This is because the upfront capital charge recovers the costs of the meter upgrade, but not of the existing meter installed before 30 June 2015.

New connections (after 1 July 2015)

For regulated new meter connections installed after 1 July 2015, the capital costs will be paid upfront by the customer. As such, no capital expenditure related to new meter connections installed after this date will be added to the metering asset base.

If a customer has a new regulated metering connection that was installed on their premises after 1 July 2015 and receives a regulated type 5 or 6 metering service, they pay the following charges:

- Non-capital component of the regulated annual metering charge.
- As they have already paid for their capital component upfront, the only costs relating to their regulated metering service left to be recovered through annual charges are the non-capital costs.

If a customer has a new regulated metering connection on their premises and wants to switch to a competitive advanced metering service (and no longer receives a regulated type 5 or 6 metering service), they stop paying all regulated annual metering charges. They will pay the following charges:

- Any charges payable to their competitive metering provider for advanced metering services. Any such charges are not subject to AER oversight and are not shown in Figure 16.4.

16.3.1.2 Annual metering service charges

We generally accept Essential Energy's building block approach as the basis for establishing annual metering charges. With respect to each building block, our final decision is:

- Opening metering asset base

  We approve an opening metering asset base (MAB) value as at 1 July 2014 of $94.6 million and substitute it for Essential Energy's proposed $95.1 million ($nominal).[79] This reflects our final decision Essential Energy's regulatory asset base (RAB) for standard control services (attachment 2).

- Depreciation

  We accept Essential Energy's approach to depreciation. Essential Energy proposed standard asset lives (15 years) which reflect the expected technical usefulness of its meters.

  Consistent with our final decision for standard control services, we specify that forecast, as opposed to actual, depreciation will apply to Essential Energy's MAB.

- Forecast capex

  Our final decision accepts Essential Energy's proposed $46.6 million in capex for annual metering charges ($2014-15).

- Forecast opex

  In assessing the metering opex building block, we used a base-step-trend approach to developing an alternative forecast. Our cost assessment led us to accept Essential Energy's proposed opex of $124.7 million ($2014–15).

  Based on our cost assessment of the individual building blocks we rejected Essential Energy's proposed price caps for annual metering charges. Our substitute price caps are set out in Appendix A.

16.3.1.3 Upfront capital charges

We accept Essential Energy's proposed price caps for new or upgraded connections, which from 1 July 2015 will be recovered as an upfront charge to customers. The charges we have accepted are set out in Appendix A.

16.3.1.4 Meter transfer fee

We do not approve a meter transfer fee. We find that there are no additional tasks or functions these distributors will have to assume when customers change meter provider. Thus there are no incremental costs.

16.3.1.5 Control mechanism

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[79] Essential Energy, *Revised regulatory proposal, Attachment 9.6 PRTM RRP*, January 2015, p. 256.

Our final decision is to apply price caps for individual type 5 and 6 metering services as the form of control. Under this form of control a schedule of prices is set for the first year. For the following years the previous year's prices are adjusted by CPI and an X factor. The control mechanism formula is set out below:

$\bar{p}_i^t \geq p_i^t$ i=1,...,n and t=1,2,3,4

$$\bar{p}_i^t = \bar{p}_i^{t-1}(1+\Delta CPI_t)(1-X_i^t)$$

Where:

$\bar{p}_i^t$ is the cap on the price of service i in year t. However, for 2015–16 this is the price as determined in Appendix A.

p_i^t is the price of service i in year *t*.

$$\Delta CPI_t = [\frac{CPI_{Mar,t-2} + CPI_{Jun,t-2} + CPI_{Sep,t-1} + CPI_{Dec,t-1}}{CPI_{Mar,t-3} + CPI_{Jun,t-3} + CPI_{Sep,t-2} + CPI_{Dec,t-2}}] - 1$$

CPI means the all groups index number for the weighted average of eight capital cities as published by the ABS, or if the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best estimate of the index.

X_i^t x is:

for the annual metering charges, the factors set out in Table 16.16

for the upfront capital charges, the factors set out in Table 16.17.

Table 16.16 – AER final decision X factors for annual metering charges (per cent)

	2016–17	2017–18	2018–19
X factor	–1.36	–1.36	–1.36

Source: AER analysis

Table 16.17 – AER final decision X factors for upfront capital charge (per cent)

	2015–16	2016–17	2017–18	2018–19
X factor	0.0	0.0	0.0	0.0

Source: AER analysis

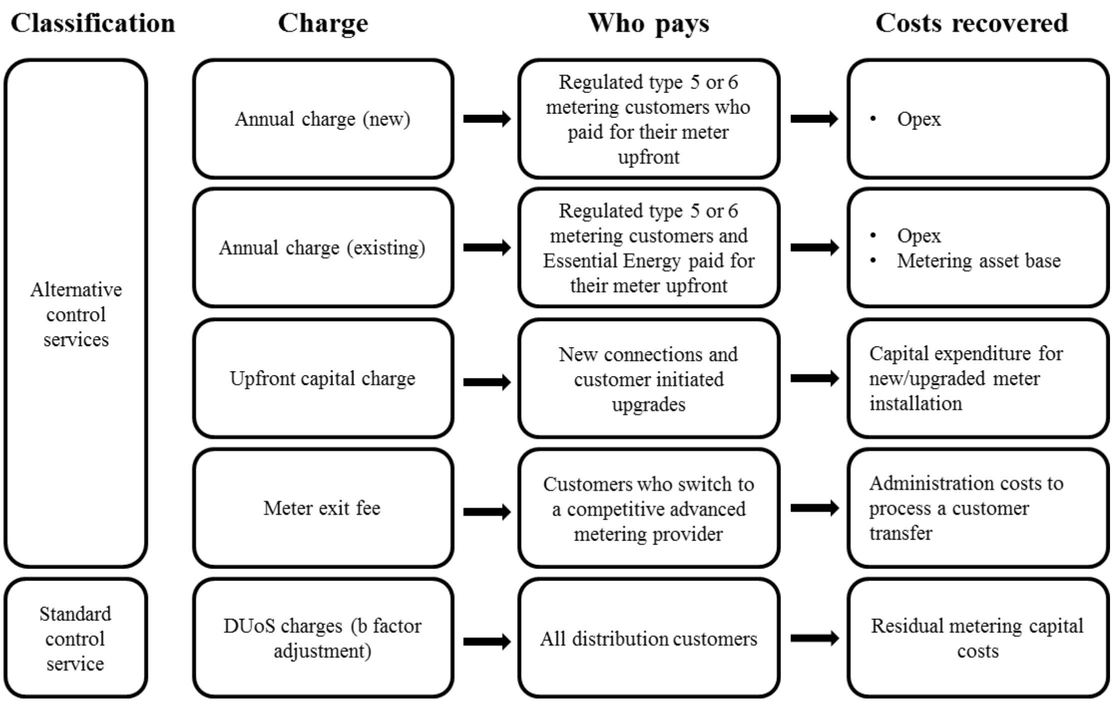
We will check for compliance with the control mechanism during the annual pricing process. To be compliant, Essential Energy must annually adjust individual price caps in accordance with the control mechanism formula shown above. Further, Essential Energy must show that individual prices are less than or equal to the approved price cap for that individual service through providing a copy of their published price list for that year.

16.3.2 Essential Energy's proposal

In January 2015, Essential Energy submitted its revised metering proposal for the 2015–19 regulatory control period.

16.3.2.1 Structure of metering charges

Figure 16.5 – Revised proposal – structure of metering charges



Source: AER analysis

Consistent with our draft decision, Essential Energy removed the residual asset costs from the proposed exit fee.[80] However, it did not accept the tolerance limit on the b-factor and proposed instead 'all DUoS amounts be subject to one side constraint and one rule for any under or over recovery'.[81]

16.3.2.2 Annual metering services

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80 Essential Energy, *Revised Regulatory Proposal, Attachment 9.4 Type 5 & 6 Metering Services*, January 2015, p. 6.

81 Essential Energy, *Revised Regulatory Proposal, Attachment 9.4 Type 5 & 6 Metering Services*, January 2015, p. 6.

For each tariff class, Essential Energy proposed a price cap for annual metering services. It built up the costs that constitute the annual metering service charges by applying a 'building block' approach. This involved forecasting the revenue requirement for each of Essential Energy's metering cost categories and then translating this into price caps.

Table 16.18 sets out Essential Energy's proposed metering building block requirement. Table 16.19 shows proposed annual charges for metering services that recover the total proposed revenue.

Table 16.18 – Essential Energy's proposed metering building block revenue requirement ($ million, 2014–15)

	2014–15	2015–16	2016–17	2017–18	2018–19
Return on capital	8.6	9.3	9.7	10.2	10.9
Return of capital	2.7	3.3	3.8	4.5	5.3
Operating expenditure	25.9	26.4	26.9	27.3	28.1
Tax	0.1	1.6	3.3	2.0	2.2
Total proposed revenue	37.3	40.5	43.8	43.9	46.5

Source: Essential Energy, *Revised regulatory proposal, Attachment 9.6, Metering PTRM*, January 2015. Converted to $2014-15.

Table 16.19 – Essential Energy's proposed prices for annual metering services ($2014–15)

Tariff class	Average price per annum (2015–165 to 2018–19)
Existing customers	
Residential anytime	34.51
Residential time of use	42.63
Small business anytime	34.51
Small business time of use	42.63
Controlled load	12.38
Solar (gross meter only)	41.03
New customers from 2015-16 onwards	
Anytime customers	14.51
Time of use customers	19.33
Controlled load	4.63
Solar additions (assuming single phase 2 element)	18.90

Source: Essential Energy, *Revised regulatory proposal, Attachment 9.5, Type 5 and 6 metering services model*, January 2015. Converted to $2014-15.

16.3.2.3 New or upgraded meters

Where Essential Energy installs a meter for a new or upgraded connection at a customer's premises, Essential Energy proposed caps (or ceilings) on the prices it can charge. In the 2014–15 placeholder year the cost of such installations will be recovered as part of the annual metering services charge. From 1 July 2015, however, new or upgraded connections will require a customer to make a full upfront capital contribution.

Table 16.20 sets out Essential Energy's proposed charges for new or upgraded meters. For ease of reference, average prices for the 2015–19 regulatory control period are shown.

Table 16.20 – Essential Energy's average proposed new or upgraded meter prices in the 2015–19 regulatory control period ($ 2014–15)

Meter description	Price
Single phase accumulation	35.14
Three phase accumulation	132.76
Single phase time of use	97.80
Single phase 2 element (time of use)	230.01
Three phase time of use	322.08
Three phase current transformer	458.57

Source: Essential Energy, *Revised regulatory proposal, Attachment 9.5, Type 5 and 6 metering services model*, January 2015. Converted to $2014-15.

16.3.2.4 Meter transfer fee

Essential Energy proposed a meter transfer fee of $47.68 which "reflects the incremental administration and disposal costs associated with a customer switching to an alternate metering service provider."[82] It also questioned our draft decision to not accept Marsden Jacob's recommendation for a meter transfer fee. [83]

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[82] Essential Energy, *Revised Regulatory Proposal*, Attachment 9.4, January 2015, pp. 7–8.

[83] Essential Energy, *Revised Regulatory Proposal*, Attachment 9.4, January 2015, p. 7.

16.3.2.5 Control mechanism

Our draft decision set the X-factors for metering services at zero. Essential Energy revised proposal stated that it agrees with this approach.[84] This is because 'wage and cost escalators [have] already [been] included in the price build-up for metering charges over the regulatory period'.[85]

16.3.3 Assessment approach

Essential Energy has proposed price caps on three categories of metering services. These are annual metering services, upfront capital charges for new or upgraded connections, and a meter transfer fee.

16.3.3.1 Structure of metering charges

AEMC Draft Rule Change

AEMC's draft rule change does not specify a method, but considered that the AER should determine how distributors recover residual capital costs of its regulated metering service in accordance with the existing regulatory framework.[86]

National Electricity Law

We had regard to the national electricity objective and the revenue and pricing principles which include providing a distribution business with a reasonable opportunity to recover at least its efficient costs.[87]

National Electricity Rules

We had regard to the distribution pricing principles set out in 6.18.5 which includes the requirement that revenue recovered should be between standalone and avoidable cost of serving that customer group.

In determining the appropriate structure of metering charges we have made decisions on the classification of the service and the control mechanism. The classification and control mechanism to recover metering capital costs that risk becoming stranded if a customer switches was not explicitly considered in our Stage 1 Framework and Approach.[88] Our final decision classification and control mechanism has been made

[84] Essential Energy, *Revised Regulatory Proposal*, Attachment 9.4, January 2015, p. 12.

[85] Essential Energy, *Revised Regulatory Proposal*, Attachment 9.4, January 2015, p. 12.

[86] AEMC, Draft Rule Determination (Expanding competition in metering and related services), 26 March 2015, p. 225.

[87] NEL, Revenue and Pricing Principles, 7A (2).

[88] NER, cl. 6.12.3 (b) (cl). We may depart from the classification and control mechanism decisions made in our framework and approach paper if we consider there have been unforeseen circumstances. The unforeseen circumstance in this case was that there previously was no stranding risk because customers had no choice to exit regulated metering. As such, we did not consider residual metering costs in our framework and approach paper (March 2013) which was released prior to SCER metering rule change request (October 2013).

with regard to the factors set out in clauses 6.2.2(c) and 6.2.5 (c) of the NER. We had particular regard to:

- how the classification/control mechanism may influence the potential for competition in unregulated metering
- a method that provides administrative simplicity for customers, Essential Energy and the AER where possible
- the extent to which costs can be directly attributable to individual customers in order to minimise cross subsidies.

We also have a preference for a nationally consistent approach. Our approach to the classification of services is discussed in Attachment 13.

16.3.3.2 Annual metering service charges

We assessed Essential Energy's proposed opening MAB, depreciation, operating and capex components associated with the annual metering service.

Opening metering asset base

In assessing Essential Energy's proposed opening MAB, we reviewed how Essential Energy had separated its proposed opening MAB as at 1 July 2014, from the RAB for standard control services.

Depreciation

With respect to depreciation, we considered the remaining asset lives Essential Energy proposed and had regard to the opening of competition to metering services.

Forecast capex

In assessing the proposed forecast capex, our assessment approach did not change from our draft decision. We reviewed Essential Energy's unit costs and volume forecasts. More specifically, we assessed Essential Energy's proposed 'material' and 'non–material' unit costs and the forecast volume of reactive and proactive replacements. Material costs relate to the hardware used to provide metering services. Non–material costs relate to the labour activities which Essential Energy must perform to install a new or replaced meter.

From 1 July 2015, Essential Energy's customers will incur an upfront payment recovering the capital cost of meters installed at ‘new or upgraded connections’. The commencement date for the upfront payment (1 July 2015) is the earliest available under the NER. This provides that the existing cost allocation approach leading up to the placeholder year must be retained into 2014–15.[89] In the case of new or upgraded connections, the capital cost of the meters must be recovered under the general network charge for standard control services. However from 1 July 2015, Essential

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[89] NER, cl. 6.15.2(7).

Energy proposed to change its capital contribution policy so that such costs are recovered directly from customers.

New or upgraded connections in 2014-15 formed part of our assessment of Essential Energy's proposed capex building block for annual metering services. However the 'true–up' of any differences between the capital costs Essential Energy recovered in the 2014–15 placeholder year with our assessment of what we consider to be prudent and efficient will be recovered under the general network service charge.

Forecast opex

We applied the same approach to assessing Essential Energy's proposed opex, as in our draft decision.

Opex refers to the operating, maintenance and other non–capital costs, including labour, incurred in the provision of metering services.

After determining Essential's efficient base opex, and accounting for any (positive or negative) step changes, we trended forward that amount over the 2015–19 regulatory control period. This is known as the 'base, step and trend' approach.

Base

As opex is largely recurrent in nature, we considered Essential Energy's historical costs to be a useful starting point to establish a base to forecast future costs. We also used benchmarking to assess the relative efficiency of the base year compared with comparable network businesses in the national electricity market.

Our base assessment uses historical data over a five year period, rather than selecting a single base year. Given that we do not apply an efficiency benefit sharing scheme (EBSS) to alternative control services, we consider an average of multiple years to be a better measure of a business' efficient base; it avoids any incentive to 'load' a single base year with expenditure going forward.

We used 'opex for metering' data collected in our economic benchmarking regulatory information notices (RIN). This audited data is suitable for comparison because the data provided by the distributors was prepared according to a consistent set of instructions and definitions.[90]

Our metering assessment relates to annual charges for default metering services common to all regulated Type 5 and 6 metering customers. There are also ancillary metering services paid for by customers specifically requesting a service like an off-cycle meter read or a meter accuracy test. However, the economic benchmarking metering opex data does not distinguish between ancillary and default metering services. We did not make this adjustment for the draft decision, but have adjusted

[90] AER, *Economic benchmarking RIN for distribution network service providers - Instructions and Definitions - Sample*, November 2013.

base metering opex data to exclude ancillary metering service costs for the final decision.

With this adjusted base data, we then performed our benchmarking analysis. We used a partial performance indicator for our benchmarking analysis. This compared historic annual metering opex per customer across non-Victorian distributors[91] in the national electricity market.

Our benchmarking analysis for metering is a simpler version than what we used to assess standard control opex. This reflects the generally lighter handed regulatory approach to alternative control services compared with standard control services. For example, our econometric modelling results we used to assess standard control opex were based on data for network services and therefore do not strictly apply to metering services.

As with our draft decision, we adjusted the benchmarking results for customer density. This is a network characteristic which exogenously influences opex requirements.

We also took Essential Energy's revised regulatory proposal into account. In particular, we considered if Essential Energy had demonstrated whether any further exogenous influences, other than customer density, should be taken into account.[92]

Step changes

When assessing a distributor's proposed step changes, we consider whether they are needed for the total opex forecast to reasonably reflect the opex criteria.[93] Our assessment approach is consistent with our *Expenditure forecast assessment guideline*.[94]

We generally consider an efficient base level of opex is sufficient for a prudent and efficient distributor to meet all existing regulatory obligations. This is the same regardless of whether we forecast an efficient base level of opex based on the service provider's own costs or the efficient costs of comparable benchmark providers. We only include a step change in our opex forecast if we are satisfied a prudent and efficient service provider would need an increase in its opex.

Step changes should generally relate to a new obligation or some change in the service provider's operating environment beyond its control. It is not enough to simply demonstrate an efficient cost will be incurred for an activity that was not previously undertaken.

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91 Victorian distributors rolled out advanced metering technology in the last regulatory period. These costs are not comparable to other distributors which have type 5 and 6 meters.

92 AER, *Draft decision on Essential Energy's regulatory proposal: 2014–15 and 2015–19*, November 2014, p. 16–43.

93 NER, clause 6.6.5(c)

94 AER, *Expenditure assessment forecast guideline*, November 2013, p.11, 24.

Trend

For both capital and operating expenditure, we had regard to the capital and operating expenditure objectives and criteria in chapter 6 of the NER.[95] Though these considerations relate to standard, as opposed to alternative, control services, they are helpful and relevant in providing a general framework for assessing a building block expenditure forecast. Among other things, when considering a distribution business's forecast, the capital and operating expenditure objectives and criteria state we should consider:

- the efficient costs required
- the costs a prudent operator would incur
- whether the proposed cost inputs are realistic.[96]

16.3.3.3 Upfront capital charge

To assess the reasonableness of the proposed charges from 1 July 2015, we analysed Essential Energy's unit costs. We did not consider the forecast volumes of new or upgraded connections for the 2015–19 regulatory control period; they have no bearing on the quantum of the upfront charge.

16.3.3.4 Meter transfer fee

Our draft decision did not make an explicit decision on the meter transfer fee proposed by Essential Energy. It sought more evidence from distributors as to the quantum and rationale for these fees. Stakeholders' views were also sought.

We must balance revenue recovery for the efficient costs of the distributor's service provision with identifying and removing barriers to entry and competition, consistent with the proposed metering rule change submitted by the COAG Energy Council and currently being deliberated by the Australian Energy Market Commission.[97]

We undertook a cost assessment underlying the proposed meter transfer fees to determine the efficiency of those costs. To asses costs we considered the activities either required, or reasonably expected to be required, for a meter transfer, by both a distributor and a competing metering provider. We had regard to the costs estimated to be incurred from such activities in New South Wales, the Australian Capital Territory, Queensland and South Australia. Victorian distributors are under a State Government mandated smart meter roll out, and so meter transfer is not a comparable activity that can be presently undertaken and therefore benchmarked.

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95 NER, cll. 6.5.6 and 6.5.7.

96 NER, cll. 6.5.6(c) and 6.5.7(c).

97 Australian Energy Market Commission, Draft rule determination, Expanding competition in metering and related services, 26 March 2015.

We consulted with first and second tier retailers and the Australian Energy Market Operator to ascertain those activities necessary for the efficient transfer of meter customers among service providers. The New South Wales and Australian Capital Territory distributors' revised revenue proposals, and the initial proposals from Queensland and South Australia's distributors, outlined the activities they would undertake to transfer customers.

16.3.4 Interrelationships

Our final decision should provide Essential Energy with an opportunity to recover at least its efficient costs.[98] This includes, where relevant, providing enough expenditure for the business to repay its debt financing costs and earn a reasonable return on its investments.

Our final decision on Essential Energy's alternative control metering proposal, therefore, interrelates with our assessment of its proposed rate of return. Refer to attachment 3 of this preliminary decision for the rate of return we accept for direct control services,[99] along with our reasons. Unlike standard control services, we will not be annually adjusting for the return on debt for alternative control services. The only annual changes for price caps for alternative control services will be consistent with our price control mechanism formula.

16.3.5 Reasons for final decision

16.3.5.1 Structure of metering charges

Our final decision approves two types of charges:

- Upfront capital charge (for all new and upgraded meters installed from 1 July 2015)
- Annual charge comprising two components
    - capital—metering asset base (MAB) recovery
    - non-capital—operating expenditure and tax.

We approve an upfront capital charge for two reasons. Firstly, it directly attributes the capital costs to the customer who initiates the meter installation. Secondly, it is appropriate in the context of expanding competition in metering. It is difficult to forecast the number of new regulated type 5 and 6 meters that will be installed in the upcoming 2015–19 regulatory control period. By charging upfront, we avoid having to forecast capital expenditure for new and upgraded metering installations that may not eventuate.

To better meet the distribution pricing principles, it important for annual charges to be set on a cost-reflective basis. It is particularly significant in the context of expanding

[98] NEL, Revenue and Pricing Principles, 7A (2).

[99] Direct control services include standard and alternative control services.

competition in metering. Previously, metering was a standard control service and the related metering costs were bundled into general network tariffs. There was no transparency around the costs of providing regulated metering services. By setting cost-reflective regulated metering charges, customers will be able to compare the costs of their current regulated service with offers from alternative metering providers when competition begins.

We consider that a cost-reflective annual charge for new metering connections installed after 1 July 2015 should only consist of non-capital costs (operating expenditure and tax). This is because the capital cost of meters installed after 1 July 2015 would have been fully customer funded. In contrast, pre 30 June 2015 customers on a regulated type 5 or 6 metering service who have not paid for the meter upfront should contribute to the MAB recovery through their annual charge. That is, they pay a cost-reflective annual charge that includes both capital and non-capital components. This is the way such customers pay for their regulated metering services now.

However, if a customer chooses to switch to a competitive metering provider, the capital component of the annual charge would become stranded for the distributor. That is unless there is a mechanism for recovering that cost. It is important to recognise that customers pay the capital costs of a meter on an annual basis, they represent an amortised cost (that is, have been paid for upfront by the distributor and then recovered gradually over time from customers). Past capital expenditure is a fixed cost because it does not vary with how many customers switch; the capital costs have already been incurred by the distributor to provide a regulated metering service. This is in contrast to metering operating expenditure, such as meter reading costs, which are largely variable. This means the distributor can avoid those costs if a customer switches.[100]

QCOSS considers "*it would be inappropriate to recover residual costs associated with a service that customers are not getting any benefit from…. distributors should not be allowed to recover such costs from consumers - either through a charge which is allocated across all customers nor via individual exit fees*."[101] But this effectively means that the distributor would be unable to recover the undepreciated residual value of those meters. The revenue and pricing principles provide that distributors should have a reasonable opportunity to recover at least their efficient costs. We therefore consider it appropriate that distributors recover their fixed capital costs that were incurred in providing regulated metering services.

Accordingly, we considered the most appropriate way to recover metering capital costs incurred in providing regulated metering services that risk becoming stranded if a customer switches.

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100 Although the capital costs of the meter remain to be recovered by the distributor, there is no longer any need to read the meter, thus providing an opex saving.

101 QCOSS, *Submission to AER Consultation Paper (Recovery of Residual Metering Costs)*, 31 March 2015, p 2

Essential Energy (and other distributors) initially proposed to charge an upfront exit fee when a customer wished to switch to a competitive metering provider. This would ensure they recovered their metering capital costs for existing meters that would otherwise become stranded.

However various stakeholders raised concerns that a large upfront exit fee would be a barrier to competitive entry and to the take up of advanced metering.[102] In particular, it potentially creates a first mover disadvantage because a market-led smart meter rollout is predicated on the customer not having to pay any charges upfront.[103] Therefore, the first mover competitive metering provider may have to pay for both an exit fee as well as the new smart meter—and bear the risk of those sunk costs if the customer decided to move to another competitive metering provider. We find that exit fees create a regulatory barrier to a market-led roll out of advanced metering.

There are several methods of ensuring distributors can recover capital costs incurred in providing regulated metering services. After extensive consultation with stakeholders[104], we decided on a method that we considered best balances the objectives of distributors and customers and meets regulatory objectives to promote competition in metering services.

Based on economic principles, the efficient investment signal to switch to unregulated metering would be to set individual exit fees based on the remaining economic value of the individual meter associated with the customer making the decision to switch. The remaining economic value would vary with the capability of the meter (the meter type) and remaining life (the age) of the meter. This would ensure that an existing meter would only be replaced if the new meter delivers sufficient additional economic value to cover its own cost and any remaining economic value of the existing regulated meter.

Although we considered that at a theoretical level this option has merit, at a practical level it has substantial shortcomings for a range of reasons. Firstly there is limited information as most distribution businesses do not record information about asset type or age at the individual customer level. Secondly, we are not satisfied that the amount distribution businesses are entitled to recover (based on actual costs) necessarily

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102 Consumer Challenge Panel, *Updated submission on NSW DNSPs regulatory proposals 2014-19*, 15 August 2014, pp. 36-7.
Vector Limited, *Submission on DNSPs regulatory proposals*, 8 August 2014 p. 4.
ERAA, *Submission on Issues paper NSW electricity distribution regulatory proposals*, 8 August 2014, p. 2.
Origin Energy, *Submission on NSW electricity distributors regulatory proposal (attachment 1)*, 8 August 2014, p. 33.
AGL, *Submission on NSW electricity distribution networks regulatory proposals*, 8 August 2014, p. 21.
PIAC, *Submission on NSW electricity distribution network price determination*, 8 August 2014, p. 105.

103 Vector Limited, *Submission on DNSPs regulatory proposals*, 8 August 2014 p. 4.

104 In addition to our normal consultative process which allows stakeholders to provide submissions on the distributor's proposal and our draft decision, we also held a metering workshop on 11 September 2014 and released a consultation paper (on the alternative approach to the recovery of the residual metering capital costs through an alternative control services annual charge) in March 2015. We received submissions from consumer groups, potential competitive metering providers, retailers and distributors.

corresponds to the remaining economic value of a meter. For example, if a meter fails, distributors are still allowed to recover the capital costs that were incurred to provide that meter originally–even though the meter is no longer in service and therefore has no economic value. Also, regulated historic metering costs may not be efficient, as distribution businesses have not faced competitive pressures. Finally, we were concerned that it may be inappropriate to charge customers different exit fees that would vary with meter type and age because such investment decisions were made by distribution businesses, not customers.

Our draft decision involved recovering residual metering capital costs through charges for standard control services based on actual customer switching. These residual capital costs would then be recovered from the general distribution customer base through making a b-factor adjustment to annual revenue requirements, which would have the effect of (all things equal) increasing network tariffs. To mitigate network tariff price volatility that may arise if many customers switched in the one year, we proposed a tolerance limit on the b-factor.[105]

Our draft decision approach received wide support from most stakeholders.[106] Despite having some reservations, NSW distributors largely accepted our draft decision, but did not agree with the operation of the b-factor and the tolerance limit. ActewAGL did not support our approach primarily on the basis that there may be legal concerns on whether our draft decision approach would be permissible under the NER. In particular, whether residual capital costs can be recovered through standard control services in the way proposed. Ergon Energy shared the same concern.[107]

In response to the concerns raised, we consulted on alternatives that would not require moving residual capital costs through to the standard control RAB.[108] We settled on our final decision approach because it responds to and addresses the main concerns raised by the NSW and ACT distributors and in our view also better meets the national electricity objective.

Distributors recover the same amount overall under both our draft and final decision approaches. The difference is which particular customer class pays. Under our draft

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105 AER, *Draft decision on Essential Energy's regulatory proposal: 2014–15 and 2015–19*, November 2014, p. 16–46.

106 Vector Limited, *Submission on the AER's Draft Decisions on NSW and ACT Electricity Distributors' Regulatory Proposals for 2015-16 to 2018-19*, Feb 2015, p. 3.
ERAA, *Submission on NSW DNSPs draft decision*, 13 Feb 2015, p. 1.
Origin, *Submission on NSW draft decisions*, 15 Feb 2015, p. 22.
CCP*, Submission to AER Responding to NSW draft determination and revised proposals*, Feb 2015, p.41.
AGL, *Submission to AER on NSW electricity distribution network determinations 2014-19: AER draft decisions and revised regulatory proposals*, Feb 2015, pp.1-3.
TEC, *Submission to AER on the draft determination on NSW DB's regulatory proposals 2014-19*, Feb 2015, p.2.
NCOSS, *Submission to the AER draft determination on NSW distribution business's revised regulatory proposals 2014–19*, February 2015, p.7.

107 Ergon Energy, *Submission on the draft decisions: NSW and ACT distribution determinations 2015-16 to 2018-19*, p. 35.

108 AER, *Consultation paper - Recovering the residual metering capital costs through an ACS annual charge*,March 2015.

decision, a switching customer did not directly have to pay for the residual metering capital costs related to their regulated metering service. Instead, residual capital costs would be recovered from all distribution customers through network (DUoS) tariffs, including larger customers who have never received these metering services. Switching customers only indirectly paid for a small fraction of the residual metering capital costs through the increase in network tariffs (the same increase faced by all distribution customers).

This has been amended in our final decision, such that a metering customer switching from the distributor directly shares in the recovery of residual capital costs associated with their past regulated metering service with all other metering customers. They do so by continuing to pay the same capital component of the regulated annual charge as all other metering customers until the metering asset base is fully depreciated.

Our final decision addresses the NSW businesses concerns because it ensures steady cost recovery without the need for annual corrections through a b-factor adjustment or the application of tolerance limits. It also avoids the potential legal concerns raised by ActewAGL.

We consider our final decision to have switching customers continue to pay for the capital costs associated with the regulated metering service, on balance, better meets the regulatory objectives under the NEL and NER, than either Essential Energy's initial proposal or our draft decision approach. We considered:

- Impact on competition
    - The structure and quantum of regulated metering charges impact competitive entry (both upfront exit fees and the regulated annual charge).
    - Like our draft decision, our final decision removes the upfront exit fee which was identified as the primary barrier to competitive entry by stakeholders.
    - Like our draft decision, our final decision removes concerns about first mover disadvantage that would arise if the first mover had to pay the upfront exit fee and risk being undercut by another competitive provider that does not face the exit fee. Under the final decision, the customer is charged the capital component of the regulated annual metering charge directly.
    - Relative to our draft decision, our final decision increases the costs to switch to a competitive metering provider.[109] A higher switching cost relatively lowers the incentive to switch to a competitive metering provider, so our final decision approach may result in slightly slower uptake of competitive

[109] Under our draft decision, a customer who switched only had to pay metering charges related to a competitive metering provider for their new advanced meter and a small proportion of residual metering capital costs through increased DUoS charges. Under our final decision, a customer who switches continues to pay the regulated annual charge (capital), in addition to any new advanced metering charge. The switching cost is therefore higher under our final decision.

metering services, depending on how compelling an offer is by a competitive metering provider.

- Administrative simplicity:
    - Our final decision makes use of existing information that Essential Energy has, rather than relying on further information on the remaining economic or technical life of individual metering assets which would be difficult to determine.
    - It is less complex than the draft decision which involved making annual adjustments to the b-factor and the standard control services RAB. Further, tolerance limits are no longer needed because there will be no price volatility under our final decision approach.
- The directly attributed cost to minimise cross subsidies.
    - Our final decision involves continuing to charge switching customers an ongoing regulated annual charge to recover metering capital costs associated with their past regulated metering service. We considered whether it was appropriate to continue to charge a regulated annual charge when a customer is no longer receiving an active regulated metering service. We consider that it is appropriate to charge switched customers for fixed capital costs associated with their past regulated metering services because it more directly attributes cost recovery to the customer group that caused those costs to be incurred and ensures that the distributor has an opportunity to at least recover its efficient costs. We consider this also strikes an appropriate balance to promote efficient investment as set out in the revenue and pricing principles.
    - Our draft decision involved cross subsidising residual costs across the general distribution customer base. For example, the network tariff paid by a large industrial customer who has never used a type 5 or 6 regulated metering service[110] would contribute towards paying off residual metering capital costs associated with switching customers.
    - Under our final decision, only customers at premises which currently or previously had a type 5 or 6 metering service will be paying for the capital costs incurred in providing type 5 and 6 metering services.
    - Nonetheless, our final decision still involves some cross subsidy. This is because the capital component of the annual charge is based on the average depreciated value of the MAB. We consider this is appropriate given that we do not have granular information on the customer's specific meter asset type or age.
    - Another form of cross subsidy is that the regulated annual charge (capital) a switching customer will pay for includes some recovery of forecast

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[110] Type 5 and 6 metering services are for smaller customers who consume less than 160MWh annually.

replacement capital expenditure that is not linked to the switched customer's past regulated metering service. The opening MAB value is based on past capital expenditure. The MAB is not forecast to grow much because from 1 July 2015, all new and upgraded meters will be paid for upfront and will therefore not be included in the MAB. However, some forecast capital expenditure relating to replacement meters will be added to the MAB.[111] However, this is expected to be an interim issue as it is likely that distributors will not be able to install replacement meters after the metering rule change comes into effect on 1 July 2017.[112]

- Our final decision to charge for new and upgraded meters upfront removes the risk of future cross subsidy. This is because by charging capital costs upfront, it is directly attributed and paid for by the customer choosing to install that meter. There is no risk of metering capital costs becoming stranded.

Our final decision signals a relatively higher switching cost compared to our draft decision as we explain above. This may result in slower entry by competitive entrants than our draft decision. However, we consider it appropriate that our final decision signals a lower avoidable annual cost for two reasons.

Firstly, the avoidable cost signalled under our final decision is closer to the actual avoidable cost faced by the distributor. Actual avoidable costs are variable costs the distributor no longer incurs when a customer switches. Non-capital costs (for example, meter reading) are largely variable costs. Under our existing regulatory framework, distributors are entitled to recover capital costs incurred in providing regulated metering services. Thus, the recovery of capital costs cannot be avoided even if a customer switches.

Our draft decision therefore signalled a higher than actual avoidable cost to the switching customer, which arguably might promote greater switching than what is efficient. Under the draft decision, the avoidable cost signalled to the switching customer was equal to the entire annual charge (based on both the variable non-capital and fixed capital components). Under the final decision, the avoidable cost is only the variable non-capital component of the annual charge, closer to the true avoidable cost.

Secondly, the impact on competition is not the only regulatory objective. We are required to balance a number of considerations under the NER, including the need for efficient price signals and thus minimising cross subsidies. When making our draft decision, we accepted this cross subsidy (which resulted in the relatively higher

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[111] Capital expenditure related to replacement meters is added to the MAB and recovered from all metering customers through the annual charge, rather than charged upfront. We consider this is appropriate because replacement is not initiated or controlled by the customer. A meter has to be replaced if it suddenly fails or may have to be proactively replaced because the distributor must comply with AEMO's metrology procedures.

[112] AEMC, *Expanding competition in metering and related services, Draft Rule Determination*, 26 March 2015, p. 79.

avoidable annual costs). This was preferable to the alternative of accepting a large exit fee because of the negative impact on competition. However, we consider that our final decision better balances the various objectives than both our draft decision and the initial proposal from network businesses to charge a high upfront exit fee. Our final decision removes the main barrier to competition (a high upfront exit fee) while being administratively simpler and minimising cross subsidies and therefore leading to a more efficient outcome.

16.3.5.2 Annual metering services

Our final decision is to accept Essential Energy's total proposed building block requirement for annual metering services. We maintain our draft decision accepting a building block approach to setting charges. We also accept the proposed:

- approach to depreciation
- forecast capex
- forecast opex.

However, we do not accept Essential Energy's proposed opening MAB value. This has led us to revise the proposed annual metering service charges.

Our substitute price caps are set out in appendix A.

Opening metering asset base

We approve an opening MAB value as at 1 July 2014 of $94.6 million and substitute it for Essential Energy's proposed $95.1 million ($ nominal).[113]

Our final decision accepts a lower opening MAB value as a result of our assessment of how Essential Energy's separated its metering assets from its RAB for standard control services. In particular, before separating out metering assets we have assessed that Essential Energy should have adjusted for actual capex values to reverse movements in capitalised provisions from 2009–14. Adjusting for this leads to our substitute opening MAB. See attachment 2 of this final decision for more information.

Depreciation

We accept Essential Energy's approach to depreciation. Essential Energy proposed standard asset lives (15 years) which reflect the expected technical usefulness of its meters.

Consistent with our final decision for standard control services, we specify that forecast, as opposed to actual, depreciation will apply to Essential Energy's MAB.

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[113] Essential Energy, *Revised regulatory proposal, Attachment 9.6 PRTM RRP*, January 2015, p. 256.

Capital expenditure building block

We accept Essential Energy's revised forecast of $46.6 million in capex for annual metering services ($2014–15). Our final decision is based on our assessment of Essential Energy's proposed unit costs and forecast volumes.

Unit costs

We accept Essential Energy's proposed unit costs. Our draft decision accepted Essential Energy's proposed forecasts for non–material unit costs (i.e. labour) and therefore we have not revisited this aspect of its proposal. Our consultant, Marsden Jacob, found that the majority of Essential Energy's forecast hardware prices are within the observed market ranges, and hence they have been accepted.

With regard to material unit costs, Essential Energy is in the process of transferring its metering hardware procurement processes to Networks NSW. It accordingly does not have any existing metering hardware contracts in place, but based its forecast material unit costs on offers it has received from metering equipment vendors.[114]

We engaged Marsden Jacob to assist us in assessing Essential Energy's forecast material unit costs. This involved the consultant considering the 'maximum rate that should be applied for each meter hardware category based on consideration of the rates applied across the business and a comparison against current market rates'.[115] These rates were sourced from online advertised prices and through direct engagement with major suppliers.[116] Marsden Jacob took into consideration volume discounts which would reasonably be expected to apply to metering hardware purchases made by Essential Energy.[117]

Table 16.21 – Essential Energy's forecast material unit costs, Marsden Jacobs's observed market rates, and our substitute forecast ($ 2014–15)

Description	Forecast	Markets rates	Final decision
Type 6			
Single phase accumulation meter	22.90	18.69–20.00	Accept
Three phase accumulation combination meter	86.50	86.50–100.00	Accept
Type 5			
Single phase interval (time of use capable) meter	63.72	63.72–100.00	Accept
Single phase, dual element, direct connected interval meter	149.86	126.00–150	Accept

114 Energeia, *Review of Endeavour Energy's proposed metering tariff arrangements for 2014–19*, April 2014, p. 27.

115 Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, section 2.1.1.

116 Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, section 2.1.1.

117 Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, section 2.1.1.

Three phase interval (time of use) meter	209.84	189.27–220.00	Accept
Three phase (current transformer)	298.78	Insufficient information	Accept

Source: Marsden Jacob, *Consultant report to the AER on Alternative Control Services*, October 2014, p. 33.

Marsden Jacob found that the majority of Essential Energy's material unit costs were within the range of current market rates for metering hardware.[118] The only unit cost which falls outside of that range is a type 6 single phase accumulation meter. We considered whether we should make an adjustment to Essential Energy's total proposed capex because of this; however, we observed that any adjustment would be immaterial.

Our final decision to accept Essential Energy's capex in full differs to our draft determination. At the draft determination stage, we considered the bottom end of the observed market ranges to be the benchmark for Essential Energy. We reached this conclusion on the basis that Essential Energy is likely to benefit from volume discounts when it transfers, along with Ausgrid and Endeavour Energy, its procurement processes to Networks NSW.

In Essential Energy's revised regulatory proposal, the distribution business noted that price is only one determining factor in its procurement processes.[119] Other factors include the likelihood of lower ongoing operating costs if higher quality meters are acquired. We accept that this is likely to be the case. Moreover, since our consultant observed that the majority of Essential Energy's unit costs are within the market range, our final decision is not to make any adjustments to the proposed revised capex, but to accept it in full.[120]

Forecast volumes

We maintain our draft decision accepting Essential Energy's forecast volumes of new or upgraded connections, reactive replacements, and proactive replacements. Our reasoning is set out in our draft decision.[121] In summary, we approve the forecast volume of new connections. With regard to the forecast replacement volumes, the proposed amount (191 830) is supported by sample testing data. It shows that certain makes and models of Essential Energy's meters have failed accuracy standards and need to be replaced. Table 16.22 shows the volumes we have approved.

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118 Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, section 2.1.1.

119 Essential Energy, *Revised regulatory proposal,* January 2015, p. 254.

120 Marsden Jacob Associates, Consultant report to the AER on Alternative Control Services, October 2014, section 2.1.1.

121 AER, *Draft decision on Essential Energy's regulatory proposal: 2014-15 and 2015–19*, November 2014, p. 16–39 to 40.

Table 16.22 – Forecast volumes for annual metering services

	Revised proposed	Final decision
New or upgraded connections (2014–15 only)	31 165	31 165
Replacements	191 830	191 830

Source: AER, *Draft decision on Essential Energy's regulatory proposal: 2014-15 and 2015–19*, November 2014, p. 16–39 to 40.

Forecast opex

We accept Essential Energy's proposed opex of $124.7 million ($2014–15).

Base opex

To assess the base, we observed Essential Energy's opex over a five year period (2008–09 to 2012–13). Consistent with our approach for standard control services, we further examined base metering opex by applying benchmarking.

For the final decision, we applied base adjustments to all distributors' historic metering opex data to remove ancillary metering costs before performing our benchmarking analysis. This differs from Essential Energy's initial proposal and our draft decision approach which would remove ancillary metering costs as a step change (that is, after the base analysis). We changed our approach for the final decision to remove ancillary metering costs as a base adjustment (rather than a step change) so that our benchmarking analysis more accurately compared default metering opex only.

In its original proposal Essential Energy noted that forecast opex should be adjusted for ancillary metering services. It consultant, Energeia, noted that 'Essential Energy's forecast Types 5 and 6 metering opex for the forthcoming regulatory period of $101.9 million is a positive (downward) step change of 31% in real terms relative to its historical metering opex of $146.7 million over the current regulatory period'. [122]This is a step change of $44.8m. Essential Energy confirmed that "[t]he bulk of the negative step change relates to the movement of special meter reads (disconnections, move in move out reads etc) to Ancillary network Services. There were also other minor costs that have moved to other classifications'.[123]

Our calculation of ancillary metering service costs over the based period came to $31.8m ($2014–15). This is less than Essential Energy's proposed adjustment of $44.8m. We used our calculation to make the base adjustment. This is so that we applied the same category analysis RIN data and methodology in making base adjustments for all distributors.

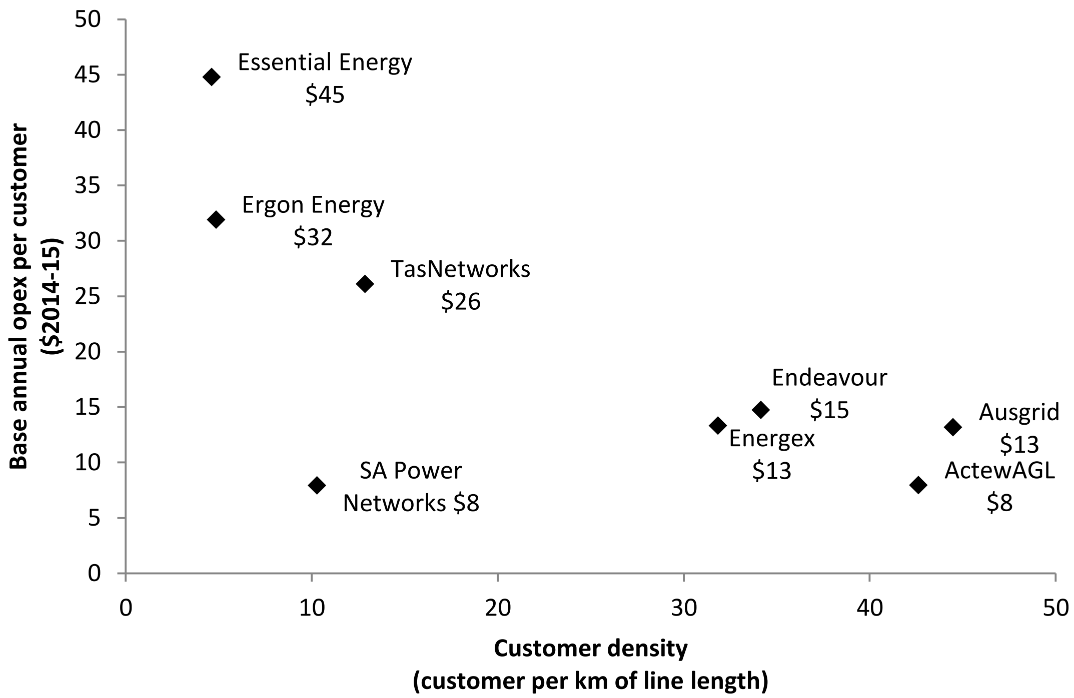
[122] Energeia, *Initial regulatory proposal, Attachment 8.04*, May 2014 p. 43

[123] AER Essential 023 Information Request, 19 September 2014, p. 4.

We used a partial performance indicator as our benchmarking method which compared Essential Energy's proposed metering opex per customer against other non-Victorian distribution businesses in the national electricity market.

When comparing Essential Energy’s proposed opex to its peers, we normalised our results by accounting for customer density. We calculated this as the number of customers a distribution business has per kilometre of line length. We took customer density into account because, all things equal, businesses with a low customer density are likely to require higher opex. For example, this could be because of longer travel times to service customers. Figure 16.6 shows the results of our benchmarking.

Figure 16.6 – Benchmarking of annual metering operating expenditure per customer ($ 2014–15)



Source: AER analysis

We observe a strong correlation between customer density and costs, and so we can reasonably expect Essential Energy to require no more opex per customer than a distribution business with a similarly dense network. Taking this approach, we consider Ergon Energy to be a relevant comparator for Essential Energy. This is because the Queensland distribution business has a similar customer density.

On a per customer basis we observed that Essential Energy's historic opex is more than Ergon Energy's historic opex. We therefore made a relative efficiency adjustment to Essential Energy's base opex to lower the forecast metering opex per customer to be in line with Ergon Energy.

In response, Essential Energy's revised regulatory challenged our efficiency adjustment on basis that there are features of its business that should be considered. Further, that when they are taken into account, 'it would appear reasonable that Essential Energy's efficient operating costs would be marginally higher than that of Ergon Energy'.[124] This was on the basis that:

- Essential Energy has a lower density of customers per kilometre of line length
- Essential Energy has on average 1.86 meters per customer compared to 1.72 meters per Ergon Energy customer
- Ergon Energy has 10 per cent more customers residing within an urban environment, while Essential Energy has nearly double the number of customers residing on a long rural feeder.

We have considered each of these factors, but do not consider any of them to have a material impact on our benchmarking results.

Essential Energy and Ergon Energy have the lowest customer densities in the national electricity market. Essential Energy has 4.671 customers per kilometre of line length, while Ergon Energy has 5.023. This is 0.352 customers less per kilometre. At such low levels of customer density, any small differences, such as those that exist between Essential and Ergon Energy, would not have an impact on the efficient level of opex. We have therefore not taken Essential Energy's slightly lower customer density in to account when benchmarking it against Ergon Energy.

As for the number of meter installations, we note that Essential Energy has slightly more meters in service per customer, than Ergon Energy. However, we do not consider this to have any impact on our benchmarking results. Both businesses are providing comparable services to approximately the same number of customers per kilometre of line length. It is at the discretion of the businesses to organise inputs to efficiently deliver these services. We therefore do not consider the slightly higher number of meters per customer to have any impact on the efficient level of opex Essential Energy requires, in the provision of metering services to customers.

Our benchmarking analysis recognises that the dispersion of customers in a distributor's area is an exogenous influence on metering opex. We used customer density as a measure for this. We do not consider it necessary to take into account urban/rural split as this essentially measures the same exogenous factor (customer density). We therefore have not made adjustments to our benchmarking for urban/rural differences.

Step changes

Essential Energy provided a step change in its initial proposal associated with the reclassification of certain metering services, like special meter reads, to ancillary

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124 Essential Energy, *Revised regulatory proposal: 1 July 2015 to 30 June 2019*, January 2015, p. 255.

network services which was accepted in principle in our draft decision, but not quantified.

However, for our final decision, we applied base adjustments to all distributors' historic metering opex data to remove ancillary metering costs to refine our benchmarking analysis so it more accurately compares only default metering historic opex.

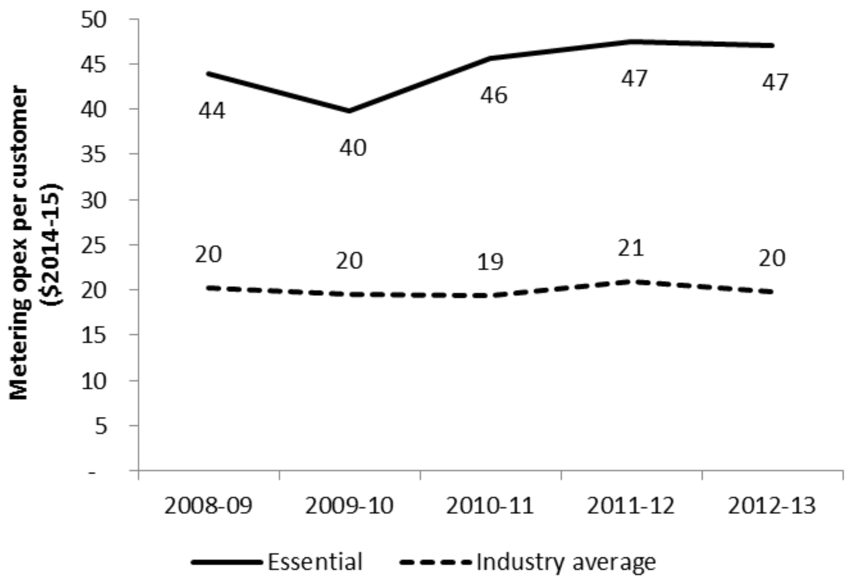
Therefore, for our final decision, we did not apply a negative step change for ancillary metering services as we accounted for this through making a base adjustment instead.

Trend

We trended the base forward for forecast metering customer growth. Consistent with our draft decision, we have applied zero forecast real price and productivity growth.

Our analysis for base metering opex used average data from 2008–09 to 2012–13. One would expect to see metering opex per customer increasing over the period if there was real price growth. However, Figure 16.7 shows that over 2008–09 to 2012–13, Essential Energy's metering opex per customer dipped in 2009–10 and then plateaued over 2010–11 to 2012–13. The industry average was stable over the period. This implies that either there were no real price increases over this period, or the distributors were able to offset these real price increases with productivity improvements.

Figure 16.7 – Annual default metering opex per customer



Given that opex is largely recurrent and metering opex per customer did not increase over the 2008–09 to 2012–13 period, we do not forecast metering opex per customer to increase in the 2015–19 regulatory control period. Therefore, we apply zero real price and productivity growth.

Our alternative forecast arrived at $133.0m ($ 2014–15). This is similar to Essential Energy's revised opex of $124.7 million ($2014–15). We therefore accept Essential Energy's proposed opex.

16.3.5.3 New/upgraded connections

We accept that all new or upgraded connections should be recovered upfront from customers. Additionally, we accept each of Essential Energy's proposed price caps for new or upgraded connections.

In assessing Essential Energy's forecast price caps, we considered the reasonableness of its proposed material and non–material unit costs. Because the price of new or upgraded connections will be recovered upfront, there was no need to consider the forecast volume of new/upgraded connections in the 2015–19 regulatory control period.

We applied the same approach to our review of Essential Energy's proposed material unit costs for new or upgraded connections, as we applied to the annual metering service charge (see section 16.3.5.2 above). In particular, we considered the proposed type 5 and 6 material unit costs against the market rates our consultant, Marsden Jacob, observed. Table 16.21 sets out our assessment based on those market rates, for both type 5 and 6 meters.

We considered whether the upfront capital charges should be annually adjusted for labour price changes. Our final decision is that no such adjustment should take place. The approved upfront capital charges are mostly made up of material costs, with only a small labour component. We therefore do not consider an annual adjustment for changes in labour prices to be reasonably required.

Appendix A contains our approved prices for new/upgraded connections.

16.3.5.4 Meter transfer fee

We do not approve a meter transfer fee for Essential Energy. We find that there are no additional tasks or functions these distributors will have to assume when customers change meter provider. Thus there are no incremental costs.

In assessing all distributors' revised proposed meter transfer fees our main focus is on the types of activities that are undertaken by retailers, distributors and metering providers in the National Electricity Market when a customer churns from a distributor owned meter. We also looked at the methodologies distributors adopted to establish the fee. Furthermore, because there is an alternative provider to that of the distributor, those providers' approach to dealing with customer meter churn and any associated costs should provide a direct comparator for that of the monopoly business.[125]

Our New South Wales and Australian Capital Territory draft decisions sought further information from distributors and the market about the veracity of meter transfer fees. As noted by Essential Energy in its revised proposal, we did not accept our consultant Marsden Jacob's recommendation of a benchmark meter transfer fee. This is because since that report, we have further consulted with stakeholders and gathered significant more information which we have incorporated into our analysis.

Retailers submitted that any activities undertaken by the distributors was no different from existing data entry/system management functions undertaken as part of normal business practice and that any incremental costs associated with 'administration' would be absorbed by the entity acquiring the metering customer.[126]

Oakley Greenwood, in its report to Origin Energy corroborated stakeholders view's by contending that changing information in the distributors systems, is likely limited to a change in information about the entity that is responsible for the meter; the identity of the metering coordinator; and sufficient information about meter type to enable its verification for tariff assignment, was probably all that was required.[127]

We tested this with retailers, many of whom are already providing metering services to large customers, which is a contestable market. Simply Energy did not agree with the imposition of administration fees; nor did Origin Energy. The latter was concerned that all three NSW distributors used vastly different inputs and therefore required testing against efficient benchmarks before a reasonable costs could be determined.[128] The retailer considered that a consistent approach to the calculation of administrative costs was most appropriate.[129]

Simply Energy observed their current role in churning meters (type 4) in the competitively provided commercial market involved administrative transaction costs that were immaterial to it. They also advised that distributors were not currently

125 Retailers in the National Electricity Market can and do provider metering services to the contestable elements of the market, namely the medium and large businesses. Distributors at this stage maintain a monopoly provision to household customers but this will change with advent of the AEMC competition in metering rule change.

126 Vector Limited, submission on the AER's draft decision on New South Wales and ACT Electricity Distributors' Regulatory Proposals for 2015–16 to 2019–20, pp. 5, 6-8, 13 February 2015, p.p. 6-7; AGL, Alternative approach to the recovery of the residual metering capital costs through an alternative control service annual charge, 27 March 2015, p.2; AGL, email to AER staff, AGL Presentation to AER staff—metering regulation & transition to competition, 13 March 2015.

127 Oakley Greenwood, Review of NSW DBs Regulatory Submission, 8 August 2014, p. 7 in Origin Energy, Submission to NSW Electricity distributors' regulatory proposals, 8 August 2014, (attachment 2).

128 Origin Energy, Ausgrid, Endeavour, Essential initial 2015–19 initial regulatory proposals, Origin submission, August 2014, (attachment 1)p. 36.

129 Origin Energy, Ausgrid, Endeavour, Essential initial 2015–19 initial regulatory proposals, Origin submission, August 2014, (attachment 2), p. 7.

charging them a meter transfer fee where the customer switched from the distributor to the retailer as metering provider.[130]

Commenting on the New South Wales distributors proposals, Simply Energy stated that there appeared no assumption of batch processing. Instead, the proposed charges assumed each meter was being processed individually. Simply Energy noted that if put in the position of the distributors, it would review processes in detail to determine the optimum batch size, which would be at least 20 meters (i.e. customers) per batch.[131] In such circumstances, multiplying Endeavour Energy's proposed five minutes per meter by 20 minutes equates to 100 minutes per batch for each manual process. Simply Energy proposed that 10 minutes was a more credible time.[132] This was also appropriate for other distributors.

Furthermore, Simply Energy advised that the reasonable activities it would have to incur to process a batch of 20 meters and the time taken for each were:

- Meter provider database update—10 minutes
- Banner system meter update—25 minutes
- Metering business system update—25 minutes
- Banner system final read update—10 minutes.[133]

This amounts to 70 minutes for a batch of 20 meters; or a total time per meter of 3.5 minutes. This is substantially less than the times proposed by any of the distributors. Given this, Simply Energy submitted that the imposition of a meter transfer fee in the residential metering market of the magnitude distributors had proposed was not justified. Rather, Simply Energy argued that the administrative costs are negligible.

Retailers as the acquirers of a new meter customer bear the costs of acquisition and must provide all relevant information to the entity that has lost the customer, in this case the distributor. This includes attending the site, removing the meter and sending it to the distributor's depot or alternative location. The retailer has an incentive to keep those costs down and to work with the business that has lost the customer—be they distributors or other retail rivals once a competitive market is established—to ensure smooth market operation. This has been the case since inception of the national electricity market for large customers. We do not find that the costs proposed by the distributors are reflective of this cost minimisation incentive.

This is confirmed by the Australian Energy Market Operator who has a new set of meter churn procedures due to commence September 2015.[134] This new procedure

130 Meeting between respective staff of Simply Energy and AER on 16 March 2015.

131 Simply Energy, metering question and churning, email to AER staff, 23 March 2015.

132 Simply Energy, metering question and churning, email to AER staff, 23 March 2015.

133 Simply Energy, metering question and churning, email to AER staff, 23 March 2015.

134 See http://www.aemo.com.au/Consultations/National-Electricity-Market/Second-Stage-Notice-of-Consultation--Meter-Churn-Package, accessed 26 March 2015 and http://www.aemo.com.au/Consultations/National-Electricity-

simplifies the meter churn procedure and places the onus on the Financial Responsible Market Participant (as the incoming Responsible Person) and their Metering Provider to update Market Settlement and Transfer Solutions and administer the transfer. The distributor's role is minimised, especially for the displacement of Type 6 legacy meters. Type 5 meters will require a final read. It could be expected that competing meter providers will be sufficiently encouraged to work with distributors to provide them with the necessary final read data. This is because to do otherwise will reduce their profit margins and potentially put them at risk of failing to meet their obligations to provide relevant data to ensure market settlement in a timely manner.[135] It is reasonable to assume that the new meter churn procedures will carry forward into the residential metering market, the competitive metering element of which is now in its infancy.

Vector agreed with the views expressed in our draft decision that Ausgrid's forecast of additional transfer costs of $59.8 million if all customers churned in 2015–19, requiring 65 extra staff, was not realistic given the relatively simple administrative task involved to process a transferred customer.

As a metering provider with experience in competitive metering markets, Vector commented on Endeavour Energy's cost assumptions in its revised revenue proposal. These are reproduced in Table 16.23 where both organisations responses can be compared.

Table 16.23 Endeavour Energy meter transfer fee build up and Vector response

Endeavour Energy Task	Endeavour Energy Time	Vector Comment
Administration Officer updates the meter removal in the Meter Provider Database.	5 min	Valid distributor activity that is currently carried out regularly now. Could not be delivered by Metering Service Provider but could be automated via distributor integration to market systems
Network Billing Data Analyst updates the meter removal and the new metering details (for the non-Endeavour Energy asset) in the Banner billing system.	5 min	Valid distributor activity that is currently carried out regularly. Could not be delivered by Metering Service Provider but could be automated by distributor via integration to market systems
Network Billing Data Analyst updates the new metering details in the Metering Business System (MBS), which will allow network billing activities to occur.	5 min	Valid distributor activity that is currently carried out regularly. Could not be delivered by Metering Service Provider but could be automated by distributor via integration to market systems

Market/~/media/Files/Other/consultations/gas/Churn%20Package%202014/Meter%20Churn%20Procedure%20FRMP%20v10%20clean.ashx accessed 26 March 2015.

135 We are aware of instances where some distributors are alleged to have deliberately stalled or frustrated attempts by large commercial users to switch meter provider. However, this is a separate issue of specific business conduct, rather than of efficient billing systems per se.

Metering Officer obtains the final read for the meter and inputs the details of the final read into Banner billing system.	5 min	Valid distributor activity that is currently carried out regularly
The ASP returns the Endeavour Energy removed asset back to the designated Endeavour Energy depot. Endeavour Energy process dictates that the meter is double bagged and goose necked to ensure safe transportation of asbestos contaminated materials. The consumables required to meet these requirements are supplied by Endeavour Energy.		Metering Service Provider could carry out on behalf of the distributor if permitted by latter. Metering Service Providers anticipate funding this activity themselves.
Cost of meter disposal.		Metering Service Provider could carry out on behalf of the distributor if permitted by latter. Metering Service Providers anticipate funding this activity themselves.

Source: Endeavour Energy; Vector Limited.

Vector advised that their response to the activities listed in Table 16.23 was that the tasks were not unique to distributors. Alternative meter service providers can now, and will in the future, undertake many of these tasks. Furthermore, they noted that Endeavour Energy could integrate these activities and tasks with electronic transactions that they presently receive from AEMO.[136] Vector says this is how it operates in the market today and did not see why distributors should not do the same. Given that distributors were performing these functions now as standard business practice, Vector could not anticipate what incremental costs would arise as a result of competitive metering.[137]

We do not agree with the distributors' position that that an increase in staff will be required within the regulatory periods commencing 1 July 2015. We also find that it will be the meter service provider, as the financially responsible market participant, who will bear the additional costs associated with meter churn, not the distributors.

We find that customers would not be paying an efficient level of costs for meter churn if the distributors proposed transfer fees were approved. A meter transfer fee of the order proposed ($47.68) could amount to a de-facto exit fee that would act as a barrier to competition and the uptake of new advanced meters. While the national electricity law requires us to ensure distributors have the opportunity to recover at least their efficient costs we are not persuaded by the evidence that distributors have material incremental costs to recover in amending records to take account of customer churn. Any incremental costs will be borne by the acquirer of the new meter customer—at the moment, retailers. Furthermore it is noteworthy that distributors are churning type 6 meters for interval meters for customers installing Solar Photovoltaic systems in large numbers without imposing any administrative fees for the meter transfer.

Further support to our findings that the proposed transfer fees are disproportionate to the activities to be undertaken is in comparing the per customer meter opex fee which

136 Vector Limited, Urgent - meter churn procedures, email to AER staff, 20 April 2015.

137 Vector Limited, Urgent - meter churn procedures, email to AER staff, 20 April 2015

we have approved in this decision. Essential Energy proposed, and we have accepted in our final decision, metering opex which equates to $31 annually per customer for meter data services, truck rolls, reading and processing, a share of information technology costs and including overheads. It does not follow that a proposed transfer fee equal or greater than this is reasonable.

We do not approve a meter transfer fee for the regulatory control period commencing 1 July 2015.

16.3.5.5 Control mechanism

In its revised regulatory proposal, Essential Energy noted that our X-factors were different between ancillary network services and metering services.[138] It is appropriate to have different X-factors because annual metering service charges and ancillary network services are built up differently.

As accepted by Essential Energy,[139] we maintain our draft decision approach to exclude wage and cost escalators as part of the X-factors for annual metering charges because we considered real price growth as part of our review of the price build-up of metering charges. However, we do include smoothing X-factors.

For upfront capital charges, we accept in principle that X-factors incorporate real price escalators, if forecast real price growth can be substantiated. We set the X-factor at zero because the cost build-up of the upfront capital charges is mostly materials, and we forecast materials growth to be no more than CPI so no real materials escalator is required.

[138] Essential Energy, *Revised regulatory proposal*, January 2015, p. 256.

[139] Essential Energy, *Revised regulatory proposal*, January 2015, p. 256.

A Alternative control services final decision price list

A.1 Ancillary network services

Table 16.24 Ancillary network services – Final decision

		Basis	Proposed price ($2014–15)	AER final decision ($2014–15)	Difference (per cent)
DESIGN FEES					
Design cert. - UG urban					
	Up to 5 Lots	/ application	276.71	276.71	–
	6 to 10 Lots	/ application	415.06	415.06	–
	11-40 Lots	/ application	691.77	691.77	–
	Over 40 Lots	/ application	830.12	830.12	–
Design cert - OH rural					
	1 to 5 Poles	/ application	276.71	276.71	–
	6 to 10 Poles	/ application	415.06	415.06	–
	11 or more poles	/ application	691.77	691.77	–
Design cert. - UG C&I or rural					
	1 to 5 Poles	/ lot	415.06	415.06	–
	6 to 10 Poles	/ lot	553.41	553.41	–

	11 or more poles	/ lot	830.12	830.12	–
Design Certification - other					
	R3 time	/ hour	138.35	138.35	–
C&I developments	R2a time	/ hour			
Asset relocation or streetlighting	R2a or R3	/hour			
Design rechecking					
UG urban, OH rural, UG C&I or rural	R2a time	/ hour	138.35	138.35	–
C&I developments	R3 time	/ hour	186.32	177.52	-4.7
Asset relocation or streetlighting	R2a or R3	/hour			
Design info. - UG urban					
	Up to 5 Lots	/ application	415.06	415.06	–
	6 to 10 Lots	/ application	553.41	553.41	–
	11-40 Lots	/ application	968.47	968.47	–
	Over 40 Lots	/ application	1245.18	1245.18	–
Design info. - other					
OH rural, UG C&I or rural, C&I developments	R2a time	/ hour	138.35	138.35	–
Asset relocation or streetlighting	R2a or R3				

ASP FEES				
Authorisation of ASPs - Initial				
Initial Authorisations	/ authorisation	789.91	652.68	-17.4
Authorisation Renewals	/ authorisation	378.08	302.23	-20.1
Authorisation Training				
Authorisation Training	/ authorisation	295.84	269.64	-8.9
Remedial action of ASPs				
Remedial action of ASPs	/ hour	172.26	165.75	-3.8
CONNECTION FEES				
13 - Customer interface coordination for contestable works				
Customer i/face coord - basic	/ hour	165.75	165.75	–
Customer i/face coord - complex	/ hour	186.32	177.52	-4.7
14 - Preliminary enquiry service				
Prelim. enquiry service - basic	/ hour	165.75	165.75	–
Prelim. enquiry service - complex	/ hour	186.32	177.52	-4.7
15 - Connection offer service				

(basic or standard)					
	Conn. offer service - basic	/ application	26.54	22.26	-16.1
	Conn. offer service - standard	/ hour	138.35	138.35	–
20 - Connection/relocation process facilitation					
	Conn. / reloc. process facilitation	/ hour	138.35	138.35	–
22 - Planning studies					
	Connection planning studies	/ hour	186.32	177.52	-4.7
23 - Services involved in obtaining deeds of agreement					
	Deeds of agreement studies	/ hour	186.32	177.52	-4.7
DISCONN - RECONN FEES					
Reconnect/Disconnect (site visit)					
	Site Visit	/ application	88.36	88.36	–
Reconnect/Disconnect Completed					
	Reconnect/Disconnect Completed	/ application	117.94	117.94	–
Reconnect/Disconnect - Technical					
	Reconnect/Disconnect -	/ application	117.94	117.94	–

	Technical				
Reconnect/Disconnect - Pillar or Pole Completed					
	Reconnect/Disconnect - Pillar or Pole Completed	/ application	434.88	434.88	–
Reconnect/Disconnect - Out of Business Hours					
	Reconnect/Disconnect - Out of Business Hours	/ application	116.73	114.22	-2.2
FIELD SERVICES FEES					
AMS - Meter Test					
	First Meter	/ application	429.17	429.17	–
	Each Additional Meter	/ application	315.57	315.57	–
AMS - Franchise CT Meter Install					
	AMS - Franchise CT Meter Install	/ install (quotation basis)	1106.19	969.05	-12.4
Off Peak Conversion Fee					
	Off Peak Conversion Fee	/ application	77.84	77.84	–
Rectification Works - General					
	Rectification Works - General	(quotation basis)	354.03	354.03	–
High Load Escorts					

	High Load Escorts	/job (quotation basis)	165.75	165.75	–
Temporary Supply					
	Install and remove HV LL Links	/ application	3314.92	3314.92	–
	Break and remake HV bonds	/ application	2486.19	2486.19	–
	Break and remake LV bonds	/ application	1988.95	1988.95	–
	Connect and disconnect generator to OH mains	/ application	1988.95	1988.95	–
	Connect and disconnect MG to LV board in Kiosk	/ application	1325.97	1325.97	–
Attendance (statutory)					
	Attendance (statutory)	/ hour	126.23	126.23	–
MIMO READS FEES					
Vacant Premise reconnect/disconnect					
	Per connection	/ application	117.94	117.94	–
Vacant Premise r/d (site visit only)					
	Per visit	/ application	88.36	88.36	–
Move In/Move Out Read and Special Read					

	Per reading	/ application	77.84	77.84	–
MISCELLANEOUS FEES					
Conveyancing Enquiry					
	Conveyancing Enquiry	/ application	58.04	49.38	-14.9
Site establishment					
	Per NMI	/ application	82.76	66.79	-19.3
OFFICE FEES					
Access - Standby					
	Access - Standby	/ hour	165.99	165.75	-0.2
Notice of Arrangement					
	Notice of Arrangement	/ application	276.71	276.71	–
Network tariff change					
	Network tariff change	/ application	35.39	–	We do not approve this fee.
Debt Collection Costs - dishonoured trans.					
	Debt Collection Costs - dishonoured trans.	/ application	31.13	31.13	–
ROLR Services					
	ROLR Services	/ event	58.86	58.86	–

		(quotation basis)
Rectification works—rectification of illegal connection		/ service (quotation basis)
Rectification works—provision of additional crew	R4 time	/ hour (quotation basis)
Rectification works—fitting of tiger tails	R4 time	/ hour plus rental (quotation basis)

				Proposed price ($2014-15)			AER final decision ($2014-15)			Difference (per cent)	
INSPECT AND CW RELATED FEES											
ASP inspection L1 - UG urban			Class A	Class B	Class C	Class A	Class B	Class C	Class A	Class B	Class C
	First 10 Lots	/ application	82.87	198.90	414.36	82.87	198.90	414.36	–	–	–
	11-40 Lots	/ application	82.87	116.02	232.04	82.87	116.02	232.04	–	–	–
	Over 40 Lots	/ application	16.57	66.30	111.05	16.57	66.30	111.05	–	–	–
ASP inspection L1 - OH rural											
	1-5 poles	/ application	99.45	198.90	331.49	99.45	198.90	331.49	–	–	–
	6-10 poles	/ application	82.87	165.75	306.63	82.87	165.75	306.63	–	–	–

	11 or more poles	/ application	71.40	116.02	249.89	71.40	116.02	249.89	–	–	–
ASP inspection L1 - UG C&I or rural											
	First 10 Lots	/ application	82.87	198.90	414.36	82.87	198.90	414.36	–	–	–
	Next 40 Lots	/ application	82.87	198.90	414.36	82.87	198.90	414.36	–	–	–
	Remainder	/ application	82.87	198.90	414.36	82.87	198.90	414.36	–	–	–
ASP inspection L1 - C&I developments											
	ASP inspection L1 - C&I developments	/ hour		165.75			165.75			–	
ASP inspection L1 - AR or SL											
	ASP inspection L1 - AR or SL	/ hour		165.75			165.75			–	
ASP inspection L2											
	A Grade	/ application		41.44			41.44			–	
	B Grade	/ application		69.62			69.62			–	
	C Grade	/ application		198.89			198.89			–	
ASP											

reinspection					
	ASP reinspection	/ hour	165.75	165.75	–
Substation Commissioning - UG Urban					
	Per Lot	/ application	2422.16	2307.73	-4.7
Substation Commissioning - Other					
	Per substation	/ application	2422.16	2307.73	-4.7
Access Permits - UG urban					
	Per Lot	/ application	2608.48	2485.25	-4.7
Access Permits - other					
	Max per access permit	/ application	2608.48	2485.25	-4.7
Admin - UG urban					
	Up to 5 Lots	/ application	424.67	356.22	-16.1
	6-10 Lots	/ application	530.83	445.28	-16.1
	11-40 Lots	/ application	743.17	623.39	-16.1
	Over 40 Lots	/ application	849.34	712.45	-16.1

Admin - OH rural				
Up to 5 poles	/ application	424.67	356.22	-16.1
6-10 poles	/ application	530.83	445.28	-16.1
11 or more poles	/ application	955.50	801.50	-16.1
Admin - other				
Max fee at six hours	/ application	637.00	534.33	-16.1

Table 16.25 Maximum hourly labour rates (including on-costs and overhead) for quoted services ($2014–15)

Classification	AER final decision maximum labour rate - includes on-cost and overhead	AER final decision maximum labour rate (overtime) - includes on-cost and overhead
Administration (R1)	89.06	121.72
Technical specialist (Indoor technical officer, R2a)	138.35	189.10
Technical specialist (Outdoor technical officer, R2b)	165.75	217.57
Engineering officer (R3)	177.52	234.09
Field worker (R4)	126.23	163.54
Field worker (Line worker 9)	126.23	163.54

Source: Marsden Jacob; Essential Energy, *Revised regulatory proposal: Attachment 9.9: Ancillary network services models*, January 2015.

Table 16.26 AER final decision X factors for ancillary network services (per cent)

	2015–16	2016–17	2017–18	2018–19
X factor	–1.02	–1.07	–1.11	–1.10

Source: AER analysis.

Note: To be clear, labour escalators themselves are positive for each year of the regulatory control period. However, the labour escalators in this table are operating as defacto X factors. Therefore, they are negative.

A.2 Public Lighting

Table 16.27 Public lighting 2015-16 Prices – Final decision

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights	SLUOS charge	
				Revised proposal	Final decision
FLU0010-ST-0990-001-B	1	STEEL POLE	1	$ 151.85	$ 133.87
FLU0050-ST-0010-001-B	1	SHARED OR NO POLE	1	$ 62.62	$ 53.60
FLU0050-ST-0740-001-B	1	SHARED OR NO POLE	2	$ 69.93	$ 60.27
FLU0060-ST-0010-001-B	1	SHARED OR NO POLE	1	$ 64.93	$ 55.52
FLU0060-ST-0810-001-B	1	WOOD POLE	1	$ 117.05	$ 101.85
FLU0060-ST-0990-001-B	1	STEEL POLE	1	$ 154.25	$ 135.87
FLU0080-ST-0010-001-B	1	SHARED OR NO POLE	1	$ 70.26	$ 59.95
FLU0100-ST-0010-001-B	1	SHARED OR NO POLE	1	$ 62.48	$ 53.49
FLU0130-ST-0010-001-B	1	SHARED OR NO POLE	1	$ 61.14	$ 52.37
FLU0130-ST-0740-001-B	1	SHARED OR NO POLE	2	$ 68.45	$ 59.03
FLU0130-ST-0810-001-B	1	WOOD POLE	1	$ 113.26	$ 98.70
FLU0130-ST-0990-001-B	1	STEEL POLE	1	$ 150.47	$ 132.72
FLU0130-ST-1000-001-B	1	STEEL POLE	2	$ 150.95	$ 133.71
FLU0140-ST-0010-001-B	1	SHARED OR NO POLE	1	$ 62.45	$ 53.46
FLU0140-ST-0810-001-B	1	WOOD POLE	1	$ 114.57	$ 99.79

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
FLU0190-ST-0010-001-B	1	SHARED OR NO POLE	1	$ 67.52	$ 57.68
FLU0240-ST-0010-001-B	1	SHARED OR NO POLE	1	$ 66.00	$ 56.41
FLU0350-ST-1620-001-B	1	SHARED OR NO POLE	1	$ 81.39	$ 69.39
HPS0010-ST-0040-001-B	1	SHARED OR NO POLE	1	$ 89.34	$ 75.94
HPS0010-ST-0360-001-B	1	STEEL POLE	1	$ 178.67	$ 156.29
HPS0010-TA-0090-001-B	1	SHARED OR NO POLE	1	$ 89.86	$ 76.46
HPS0010-TA-0140-001-B	1	WOOD POLE	1	$ 141.98	$ 122.79
HPS0010-TA-0170-001-B	1	STEEL POLE	1	$ 179.18	$ 156.81
HPS0010-TA-1210-001-B	1	WOOD POLE	2	$ 144.35	$ 125.55
HPS0020-ST-0040-001-B	1	SHARED OR NO POLE	1	$ 92.50	$ 78.57
HPS0020-ST-0350-001-B	1	WOOD POLE	1	$ 144.63	$ 124.90
HPS0020-ST-0360-001-B	1	STEEL POLE	1	$ 181.83	$ 158.92
HPS0020-ST-0730-001-B	1	STEEL POLE	2	$ 183.66	$ 161.13
HPS0020-ST-0750-001-B	1	SHARED OR NO POLE	3	$ 109.82	$ 94.35
HPS0020-ST-0890-001-B	1	SHARED OR NO POLE	2	$ 101.16	$ 86.46
HPS0020-ST-0910-001-B	1	WOOD POLE	2	$ 145.81	$ 126.57
HPS0020-TA-0090-001-B	1	SHARED OR NO POLE	1	$ 92.02	$ 78.26
HPS0020-TA-0140-001-B	1	WOOD POLE	1	$ 144.15	$ 124.59
HPS0020-TA-0170-001-B	1	STEEL POLE	1	$ 181.35	$ 158.61

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
HPS0070-ST-0040-001-B	1	SHARED OR NO POLE	1	$ 92.50	$ 78.57
HPS0090-ST-0050-001-B	1	SHARED OR NO POLE	1	$ 141.21	$ 120.27
HPS0090-ST-0220-001-B	1	WOOD POLE	1	$ 193.33	$ 166.60
HPS0090-ST-0310-001-B	1	STEEL POLE	1	$ 220.87	$ 191.81
HPS0090-ST-0690-001-B	1	STEEL POLE	2	$ 227.87	$ 198.73
HPS0090-ST-0710-001-B	1	STEEL POLE	3	$ 239.42	$ 209.45
HPS0090-ST-0980-001-B	1	WOOD POLE	2	$ 199.69	$ 172.99
HPS0090-ST-1010-001-B	1	SHARED OR NO POLE	2	$ 155.03	$ 132.87
HPS0090-ST-1360-001-B	1	R/BOUT COLUMN	3	$ 305.23	$ 269.45
HPS0090-TA-0050-001-B	1	SHARED OR NO POLE	1	$ 132.27	$ 112.83
HPS0090-TA-0220-001-B	1	WOOD POLE	1	$ 184.39	$ 159.16
HPS0090-TA-0310-001-B	1	STEEL POLE	1	$ 211.93	$ 184.37
HPS0090-TA-0690-001-B	1	STEEL POLE	2	$ 218.93	$ 191.30
HPS0090-TA-1010-001-B	1	SHARED OR NO POLE	2	$ 146.09	$ 125.44
HPS0090-TA-1370-001-B	1	R/BOUT COLUMN	4	$ 308.98	$ 273.67
HPS0100-ST-0230-001-B	1	WOOD POLE	1	$ 190.39	$ 164.16
HPS0100-ST-0430-001-B	1	STEEL POLE	3	$ 236.76	$ 207.27
HPS0100-ST-0610-001-B	1	SHARED OR NO POLE	1	$ 143.84	$ 122.91
HPS0100-ST-1070-001-B	1	WOOD POLE	1	$ 195.96	$ 169.24

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
HPS0110-ST-0060-001-B	1	SHARED OR NO POLE	1	$ 142.89	$ 121.68
HPS0110-ST-0230-001-B	1	WOOD POLE	1	$ 195.01	$ 168.01
HPS0110-ST-0320-001-B	1	STEEL POLE	1	$ 222.55	$ 193.21
HPS0110-ST-0390-001-B	1	STEEL POLE	2	$ 229.69	$ 200.27
HPS0110-ST-0470-001-B	1	STEEL POLE	4	$ 254.21	$ 222.90
HPS0110-ST-0550-001-B	1	R/BOUT COLUMN	3	$ 307.20	$ 271.11
HPS0110-ST-0590-001-B	1	R/BOUT COLUMN	4	$ 320.02	$ 282.90
HPS0110-ST-0610-001-B	1	SHARED OR NO POLE	1	$ 148.46	$ 126.75
HPS0110-ST-0760-001-B	1	WOOD POLE	2	$ 201.51	$ 174.53
HPS0110-ST-0930-001-B	1	WOOD POLE	3	$ 212.99	$ 185.19
HPS0110-ST-0960-001-B	1	SHARED OR NO POLE	2	$ 156.85	$ 134.41
HPS0110-ST-1070-001-B	1	WOOD POLE	1	$ 200.58	$ 173.08
HPS0110-ST-1120-001-B	1	STEEL POLE	1	$ 228.12	$ 198.29
HPS0110-ST-1160-001-B	1	WOOD POLE	2	$ 212.65	$ 184.68
HPS0110-ST-1450-001-B	1	R/BOUT COLUMN	4	$ 342.30	$ 303.21
HPS0110-TA-0060-001-B	1	SHARED OR NO POLE	1	$ 132.79	$ 113.28
HPS0110-TA-0230-001-B	1	WOOD POLE	1	$ 184.91	$ 159.60
HPS0110-TA-0320-001-B	1	STEEL POLE	1	$ 212.45	$ 184.81
HPS0110-TA-0390-001-B	1	STEEL POLE	2	$ 219.59	$ 191.87

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
HPS0110-TA-0590-001-B	1	R/BOUT COLUMN	4	$ 309.93	$ 274.50
HPS0110-TA-0960-001-B	1	SHARED OR NO POLE	2	$ 146.75	$ 126.01
HPS0110-TA-1120-001-B	1	STEEL POLE	1	$ 218.02	$ 189.89
HPS0110-TA-1450-001-B	1	R/BOUT COLUMN	4	$ 332.20	$ 294.81
HPS0140-ST-0070-001-B	1	SHARED OR NO POLE	1	$ 142.27	$ 121.48
HPS0140-ST-0330-001-B	1	STEEL POLE	1	$ 221.93	$ 193.02
HPS0140-ST-0400-001-B	1	STEEL POLE	2	$ 233.07	$ 203.72
HPS0140-ST-1030-001-B	1	SHARED OR NO POLE	2	$ 160.23	$ 137.86
HPS0160-ST-0070-001-B	1	SHARED OR NO POLE	1	$ 150.94	$ 128.69
HPS0160-ST-0240-001-B	1	WOOD POLE	1	$ 203.06	$ 175.02
HPS0160-ST-0330-001-B	1	STEEL POLE	1	$ 230.60	$ 200.23
HPS0160-ST-0620-001-B	1	SHARED OR NO POLE	1	$ 149.48	$ 127.36
HPS0160-ST-0770-001-B	1	WOOD POLE	2	$ 213.56	$ 185.19
HPS0170-ST-0070-001-B	1	SHARED OR NO POLE	1	$ 151.23	$ 128.94
HPS0170-ST-0240-001-B	1	WOOD POLE	1	$ 203.36	$ 175.27
HPS0170-ST-0330-001-B	1	STEEL POLE	1	$ 230.89	$ 200.47
HPS0170-ST-0400-001-B	1	STEEL POLE	2	$ 242.04	$ 211.18
HPS0170-ST-0600-001-B	1	R/BOUT COLUMN	4	$ 340.37	$ 301.10
HPS0170-ST-0620-001-B	1	SHARED OR NO POLE	1	$ 149.77	$ 127.61

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
HPS0170-ST-0660-001-B	1	SHARED OR NO POLE	2	$ 166.28	$ 142.66
HPS0170-ST-0770-001-B	1	WOOD POLE	2	$ 213.85	$ 185.43
HPS0170-ST-0900-001-B	1	WOOD POLE	2	$ 222.28	$ 193.12
HPS0170-ST-1030-001-B	1	SHARED OR NO POLE	2	$ 169.20	$ 145.32
HPS0170-ST-1080-001-B	1	WOOD POLE	1	$ 192.63	$ 166.68
HPS0170-ST-1130-001-B	1	STEEL POLE	2	$ 250.46	$ 218.86
HPS0170-ST-1170-001-B	1	STEEL POLE	1	$ 235.11	$ 204.32
HPS0170-ST-1250-001-B	1	WOOD POLE	3	$ 241.97	$ 211.27
HPS0170-TA-0070-001-B	1	SHARED OR NO POLE	1	$ 145.53	$ 124.19
HPS0170-TA-0240-001-B	1	WOOD POLE	1	$ 197.65	$ 170.52
HPS0170-TA-0330-001-B	1	STEEL POLE	1	$ 225.19	$ 195.73
HPS0170-TA-0400-001-B	1	STEEL POLE	2	$ 236.33	$ 206.43
HPS0170-TA-0600-001-B	1	R/BOUT COLUMN	4	$ 334.66	$ 296.35
HPS0170-TA-1080-001-B	1	WOOD POLE	1	$ 186.93	$ 161.94
HPS0180-ST-0860-001-B	1	R/BOUT COLUMN	3	$ 356.00	$ 313.68
HPS0180-ST-0870-001-B	1	R/BOUT COLUMN	4	$ 377.04	$ 332.95
HPS0180-ST-1490-001-B	1	R/BOUT COLUMN	2	$ 336.09	$ 295.35
HPS0250-ST-0120-001-B	1	SHARED OR NO POLE	1	$ 161.94	$ 140.00
HPS0250-ST-0840-001-B	1	R/BOUT COLUMN	3	$ 319.94	$ 283.68

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
HPS0250-ST-0850-001-B	1	R/BOUT COLUMN	2	$ 300.04	$ 265.35
HPS0250-ST-1050-001-B	1	R/BOUT COLUMN	4	$ 340.98	$ 302.96
INC0030-ST-0010-001-B	1	SHARED OR NO POLE	1	$ 45.91	$ 39.70
INC0040-ST-0010-001-B	1	SHARED OR NO POLE	1	$ 45.91	$ 39.70
INC0050-ST-0010-001-B	1	SHARED OR NO POLE	1	$ 45.91	$ 39.70
INC0100-ST-0810-001-B	1	WOOD POLE	1	$ 95.07	$ 83.56
INC0100-ST-0990-001-B	1	STEEL POLE	1	$ 132.27	$ 117.59
LPS0030-ST-0040-001-B	1	SHARED OR NO POLE	1	$ 102.00	$ 86.47
LPS0030-ST-0350-001-B	1	WOOD POLE	1	$ 154.13	$ 132.80
LPS0030-ST-0360-001-B	1	STEEL POLE	1	$ 191.33	$ 166.82
LPS0030-ST-0890-001-B	1	SHARED OR NO POLE	2	$ 110.66	$ 94.37
LPS0040-ST-0050-001-B	1	SHARED OR NO POLE	1	$ 119.37	$ 102.10
LPS0040-ST-0220-001-B	1	WOOD POLE	1	$ 171.50	$ 148.43
LPS0040-ST-0310-001-B	1	STEEL POLE	1	$ 199.03	$ 173.64
LPS0050-ST-0060-001-B	1	SHARED OR NO POLE	1	$ 122.26	$ 104.52
LPS0050-ST-0230-001-B	1	WOOD POLE	1	$ 174.39	$ 150.85
LPS0050-ST-0320-001-B	1	STEEL POLE	1	$ 201.92	$ 176.06
LPS0060-ST-0060-001-B	1	SHARED OR NO POLE	1	$ 155.60	$ 132.25
MHR0060-ST-0060-001-B	1	SHARED OR NO POLE	1	$ 124.41	$ 106.30

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
MHR0060-ST-0320-001-B	1	STEEL POLE	1	$ 204.07	$ 177.84
MHR0060-ST-0610-001-B	1	SHARED OR NO POLE	1	$ 129.98	$ 111.38
MHR0060-ST-1070-001-B	1	WOOD POLE	1	$ 182.10	$ 157.71
MHR0060-ST-1120-001-B	1	STEEL POLE	1	$ 209.64	$ 182.92
MHR0070-ST-0060-001-B	1	SHARED OR NO POLE	1	$ 124.74	$ 106.58
MHR0070-ST-0320-001-B	1	STEEL POLE	1	$ 204.40	$ 178.12
MHR0070-ST-0620-001-B	1	SHARED OR NO POLE	1	$ 127.28	$ 108.90
MHR0070-ST-1080-001-B	1	WOOD POLE	1	$ 170.14	$ 147.97
MHR0070-ST-1130-001-B	1	STEEL POLE	2	$ 227.97	$ 200.15
MHR0070-ST-1170-001-B	1	STEEL POLE	1	$ 212.62	$ 185.61
MVA0010-ST-0010-001-B	1	SHARED OR NO POLE	1	$ 69.95	$ 59.70
MVA0010-ST-0740-001-B	1	SHARED OR NO POLE	2	$ 77.26	$ 66.36
MVA0010-ST-0810-001-B	1	WOOD POLE	1	$ 122.07	$ 106.03
MVA0010-ST-0990-001-B	1	STEEL POLE	1	$ 159.28	$ 140.05
MVA0020-ST-0010-001-B	1	SHARED OR NO POLE	1	$ 69.95	$ 59.70
MVA0020-ST-0740-001-B	1	SHARED OR NO POLE	2	$ 77.26	$ 66.37
MVA0020-ST-0810-001-B	1	WOOD POLE	1	$ 122.08	$ 106.03
MVA0020-ST-0990-001-B	1	STEEL POLE	1	$ 159.28	$ 140.05
MVA0020-ST-1000-001-B	1	STEEL POLE	2	$ 159.77	$ 141.04

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
MVA0020-ST-1260-001-B	1	WOOD POLE	2	$ 121.92	$ 106.48
MVA0080-ST-0010-001-B	1	SHARED OR NO POLE	1	$ 67.79	$ 57.90
MVA0080-ST-0810-001-B	1	WOOD POLE	1	$ 119.91	$ 104.23
MVA0080-ST-0820-001-B	1	SHARED OR NO POLE	3	$ 82.41	$ 71.23
MVA0080-ST-0990-001-B	1	STEEL POLE	1	$ 157.12	$ 138.25
MVA0080-ST-1000-001-B	1	STEEL POLE	2	$ 157.60	$ 139.24
MVA0170-ST-0020-001-B	1	SHARED OR NO POLE	1	$ 95.16	$ 82.01
MVA0190-ST-0020-001-B	1	SHARED OR NO POLE	1	$ 98.13	$ 84.47
MVA0190-ST-0200-001-B	1	WOOD POLE	1	$ 150.25	$ 130.80
MVA0190-ST-0290-001-B	1	STEEL POLE	1	$ 177.79	$ 156.01
MVA0190-ST-0370-001-B	1	STEEL POLE	2	$ 185.33	$ 163.43
MVA0190-ST-0940-001-B	1	SHARED OR NO POLE	2	$ 112.49	$ 97.57
MVA0220-ST-0030-001-B	1	SHARED OR NO POLE	1	$ 110.04	$ 94.40
MVA0220-ST-0210-001-B	1	WOOD POLE	1	$ 162.17	$ 140.73
MVA0220-ST-0300-001-B	1	STEEL POLE	1	$ 189.71	$ 165.94
MVA0220-ST-0380-001-B	1	STEEL POLE	2	$ 197.40	$ 173.50
MVA0220-ST-0950-001-B	1	SHARED OR NO POLE	2	$ 124.56	$ 107.64
MVA0250-ST-0300-001-B	1	STEEL POLE	1	$ 178.03	$ 156.23
FLU0010-ST-0010-002-B	2	SHARED OR NO POLE	1	$ 43.60	$ 36.27

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
FLU0010-ST-0990-002-B	2	STEEL POLE	1	$ 57.25	$ 47.62
FLU0040-ST-0010-002-B	2	SHARED OR NO POLE	1	$ 48.27	$ 40.15
FLU0050-ST-0010-002-B	2	SHARED OR NO POLE	1	$ 43.70	$ 36.35
FLU0050-ST-0990-002-B	2	STEEL POLE	1	$ 57.34	$ 47.70
FLU0060-ST-0010-002-B	2	SHARED OR NO POLE	1	$ 46.00	$ 38.26
FLU0060-ST-0740-002-B	2	SHARED OR NO POLE	2	$ 46.00	$ 38.26
FLU0060-ST-0810-002-B	2	WOOD POLE	1	$ 60.94	$ 50.69
FLU0060-ST-0830-002-B	2	SHARED OR NO POLE	4	$ 46.00	$ 38.26
FLU0060-ST-0990-002-B	2	STEEL POLE	1	$ 59.65	$ 49.62
FLU0060-ST-1000-002-B	2	STEEL POLE	2	$ 52.82	$ 43.94
FLU0070-ST-0010-002-B	2	SHARED OR NO POLE	1	$ 48.64	$ 40.47
FLU0080-ST-0010-002-B	2	SHARED OR NO POLE	1	$ 51.33	$ 42.70
FLU0080-ST-0990-002-B	2	STEEL POLE	1	$ 64.98	$ 54.05
FLU0100-ST-0010-002-B	2	SHARED OR NO POLE	1	$ 43.56	$ 36.23
FLU0100-ST-0990-002-B	2	STEEL POLE	1	$ 57.20	$ 47.58
FLU0100-ST-1000-002-B	2	STEEL POLE	2	$ 50.38	$ 41.91
FLU0130-ST-0010-002-B	2	SHARED OR NO POLE	1	$ 42.21	$ 35.11
FLU0130-ST-0740-002-B	2	SHARED OR NO POLE	2	$ 42.21	$ 35.11
FLU0130-ST-0810-002-B	2	WOOD POLE	1	$ 57.15	$ 47.54

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
FLU0130-ST-0990-002-B	2	STEEL POLE	1	$ 55.86	$ 46.47
FLU0130-ST-1000-002-B	2	STEEL POLE	2	$ 49.04	$ 40.79
FLU0140-ST-0010-002-B	2	SHARED OR NO POLE	1	$ 43.52	$ 36.20
FLU0140-ST-0740-002-B	2	SHARED OR NO POLE	2	$ 43.52	$ 36.20
FLU0140-ST-0830-002-B	2	SHARED OR NO POLE	4	$ 43.52	$ 36.20
FLU0140-ST-0990-002-B	2	STEEL POLE	1	$ 57.17	$ 47.56
FLU0140-ST-1260-002-B	2	WOOD POLE	2	$ 50.99	$ 42.42
FLU0220-ST-0990-002-B	2	STEEL POLE	1	$ 60.72	$ 50.51
FLU0240-ST-0010-002-B	2	SHARED OR NO POLE	1	$ 47.07	$ 39.16
FLU0240-ST-0810-002-B	2	WOOD POLE	1	$ 62.01	$ 51.59
FLU0240-ST-0990-002-B	2	STEEL POLE	1	$ 60.72	$ 50.51
FLU0250-ST-0010-002-B	2	SHARED OR NO POLE	1	$ 48.47	$ 40.32
FLU0350-ST-1620-002-B	2	SHARED OR NO POLE	1	$ 60.31	$ 50.17
FLU0350-ST-1660-002-B	2	WOOD POLE	1	$ 75.25	$ 62.60
FLU0350-ST-1700-002-B	2	STEEL POLE	1	$ 73.96	$ 61.53
HPS0010-ST-0040-002-B	2	SHARED OR NO POLE	1	$ 69.07	$ 57.46
HPS0010-ST-0350-002-B	2	WOOD POLE	1	$ 84.01	$ 69.89
HPS0010-ST-0360-002-B	2	STEEL POLE	1	$ 82.72	$ 68.81
HPS0010-ST-0890-002-B	2	SHARED OR NO POLE	2	$ 69.07	$ 57.46

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
HPS0010-ST-0910-002-B	2	WOOD POLE	2	$ 76.54	$ 63.67
HPS0010-TA-0090-002-B	2	SHARED OR NO POLE	1	$ 68.40	$ 56.90
HPS0010-TA-0140-002-B	2	WOOD POLE	1	$ 83.34	$ 69.33
HPS0010-TA-0170-002-B	2	STEEL POLE	1	$ 82.05	$ 68.25
HPS0020-ST-0040-002-B	2	SHARED OR NO POLE	1	$ 72.23	$ 60.08
HPS0020-ST-0350-002-B	2	WOOD POLE	1	$ 87.17	$ 72.51
HPS0020-ST-0360-002-B	2	STEEL POLE	1	$ 85.87	$ 71.44
HPS0020-ST-0730-002-B	2	STEEL POLE	2	$ 79.05	$ 65.76
HPS0020-ST-0750-002-B	2	SHARED OR NO POLE	3	$ 72.23	$ 60.08
HPS0020-ST-0880-002-B	2	STEEL POLE	4	$ 75.64	$ 62.92
HPS0020-ST-0890-002-B	2	SHARED OR NO POLE	2	$ 72.23	$ 60.08
HPS0020-ST-0910-002-B	2	WOOD POLE	2	$ 79.70	$ 66.30
HPS0020-TA-0090-002-B	2	SHARED OR NO POLE	1	$ 70.56	$ 58.70
HPS0020-TA-0140-002-B	2	WOOD POLE	1	$ 85.50	$ 71.13
HPS0020-TA-0170-002-B	2	STEEL POLE	1	$ 84.21	$ 70.05
HPS0070-ST-0040-002-B	2	SHARED OR NO POLE	1	$ 72.23	$ 60.08
HPS0070-ST-0350-002-B	2	WOOD POLE	1	$ 87.17	$ 72.51
HPS0070-ST-0360-002-B	2	STEEL POLE	1	$ 85.87	$ 71.44
HPS0080-ST-0050-002-B	2	SHARED OR NO POLE	1	$ 72.40	$ 60.22

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
HPS0080-ST-0310-002-B	2	STEEL POLE	1	$ 86.04	$ 71.58
HPS0090-ST-0050-002-B	2	SHARED OR NO POLE	1	$ 106.10	$ 88.26
HPS0090-ST-0220-002-B	2	WOOD POLE	1	$ 121.04	$ 100.69
HPS0090-ST-0310-002-B	2	STEEL POLE	1	$ 119.75	$ 99.61
HPS0090-ST-0690-002-B	2	STEEL POLE	2	$ 112.92	$ 93.93
HPS0090-ST-0710-002-B	2	STEEL POLE	3	$ 110.65	$ 92.04
HPS0090-ST-0720-002-B	2	STEEL POLE	4	$ 109.51	$ 91.10
HPS0090-ST-0980-002-B	2	WOOD POLE	2	$ 113.57	$ 94.47
HPS0090-ST-1010-002-B	2	SHARED OR NO POLE	2	$ 106.10	$ 88.26
HPS0090-ST-1360-002-B	2	R/BOUT COLUMN	3	$ 110.65	$ 92.04
HPS0090-ST-1370-002-B	2	R/BOUT COLUMN	4	$ 109.51	$ 91.10
HPS0090-TA-0050-002-B	2	SHARED OR NO POLE	1	$ 97.16	$ 80.82
HPS0090-TA-0220-002-B	2	WOOD POLE	1	$ 112.10	$ 93.25
HPS0090-TA-0310-002-B	2	STEEL POLE	1	$ 110.81	$ 92.18
HPS0100-ST-0060-002-B	2	SHARED OR NO POLE	1	$ 103.02	$ 85.70
HPS0100-ST-0230-002-B	2	WOOD POLE	1	$ 117.96	$ 98.12
HPS0100-ST-0320-002-B	2	STEEL POLE	1	$ 116.67	$ 97.05
HPS0100-ST-0390-002-B	2	STEEL POLE	2	$ 109.84	$ 91.37
HPS0100-ST-0610-002-B	2	SHARED OR NO POLE	1	$ 103.02	$ 85.70

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
HPS0100-ST-1070-002-B	2	WOOD POLE	1	$ 117.96	$ 98.12
HPS0100-ST-1120-002-B	2	STEEL POLE	1	$ 116.67	$ 97.05
HPS0100-ST-1160-002-B	2	WOOD POLE	2	$ 110.49	$ 91.91
HPS0110-ST-0060-002-B	2	SHARED OR NO POLE	1	$ 107.64	$ 89.54
HPS0110-ST-0230-002-B	2	WOOD POLE	1	$ 122.58	$ 101.97
HPS0110-ST-0320-002-B	2	STEEL POLE	1	$ 121.28	$ 100.89
HPS0110-ST-0390-002-B	2	STEEL POLE	2	$ 114.46	$ 95.22
HPS0110-ST-0430-002-B	2	STEEL POLE	3	$ 112.19	$ 93.32
HPS0110-ST-0470-002-B	2	STEEL POLE	4	$ 111.05	$ 92.38
HPS0110-ST-0510-002-B	2	R/BOUT COLUMN	2	$ 114.46	$ 95.22
HPS0110-ST-0550-002-B	2	R/BOUT COLUMN	3	$ 112.19	$ 93.32
HPS0110-ST-0590-002-B	2	R/BOUT COLUMN	4	$ 111.05	$ 92.38
HPS0110-ST-0610-002-B	2	SHARED OR NO POLE	1	$ 107.64	$ 89.54
HPS0110-ST-0650-002-B	2	SHARED OR NO POLE	2	$ 107.64	$ 89.54
HPS0110-ST-0760-002-B	2	WOOD POLE	2	$ 115.11	$ 95.75
HPS0110-ST-0960-002-B	2	SHARED OR NO POLE	2	$ 107.64	$ 89.54
HPS0110-ST-0970-002-B	2	SHARED OR NO POLE	4	$ 107.64	$ 89.54
HPS0110-ST-1070-002-B	2	WOOD POLE	1	$ 122.58	$ 101.97
HPS0110-ST-1120-002-B	2	STEEL POLE	1	$ 121.28	$ 100.89

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
HPS0110-ST-1140-002-B	2	STEEL POLE	2	$ 114.46	$ 95.22
HPS0110-ST-1160-002-B	2	WOOD POLE	2	$ 115.11	$ 95.75
HPS0110-ST-1380-002-B	2	R/BOUT COLUMN	3	$ 112.19	$ 93.32
HPS0110-ST-1450-002-B	2	R/BOUT COLUMN	4	$ 111.05	$ 92.38
HPS0110-TA-0060-002-B	2	SHARED OR NO POLE	1	$ 97.54	$ 81.14
HPS0110-TA-0230-002-B	2	WOOD POLE	1	$ 112.48	$ 93.57
HPS0110-TA-0320-002-B	2	STEEL POLE	1	$ 111.18	$ 92.49
HPS0110-TA-0590-002-B	2	R/BOUT COLUMN	4	$ 100.95	$ 83.98
HPS0110-TA-1070-002-B	2	WOOD POLE	1	$ 112.48	$ 93.57
HPS0120-ST-0860-002-B	2	R/BOUT COLUMN	3	$ 128.15	$ 106.60
HPS0120-ST-1490-002-B	2	R/BOUT COLUMN	2	$ 130.42	$ 108.49
HPS0140-ST-0070-002-B	2	SHARED OR NO POLE	1	$ 103.02	$ 85.70
HPS0140-ST-0330-002-B	2	STEEL POLE	1	$ 116.67	$ 97.05
HPS0160-ST-0070-002-B	2	SHARED OR NO POLE	1	$ 111.69	$ 92.91
HPS0160-ST-0240-002-B	2	WOOD POLE	1	$ 126.63	$ 105.34
HPS0160-ST-0330-002-B	2	STEEL POLE	1	$ 125.34	$ 104.26
HPS0160-ST-0400-002-B	2	STEEL POLE	2	$ 118.51	$ 98.59
HPS0160-ST-0620-002-B	2	SHARED OR NO POLE	1	$ 111.69	$ 92.91
HPS0160-ST-1130-002-B	2	STEEL POLE	2	$ 118.51	$ 98.59

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
HPS0160-ST-1170-002-B	2	STEEL POLE	1	$ 125.34	$ 104.26
HPS0170-ST-0070-002-B	2	SHARED OR NO POLE	1	$ 111.98	$ 93.15
HPS0170-ST-0240-002-B	2	WOOD POLE	1	$ 126.92	$ 105.58
HPS0170-ST-0270-002-B	2	R/BOUT COLUMN	3	$ 116.53	$ 96.94
HPS0170-ST-0330-002-B	2	STEEL POLE	1	$ 125.63	$ 104.51
HPS0170-ST-0400-002-B	2	STEEL POLE	2	$ 118.81	$ 98.83
HPS0170-ST-0440-002-B	2	STEEL POLE	3	$ 116.53	$ 96.94
HPS0170-ST-0480-002-B	2	STEEL POLE	4	$ 115.39	$ 95.99
HPS0170-ST-0560-002-B	2	R/BOUT COLUMN	3	$ 116.53	$ 96.94
HPS0170-ST-0600-002-B	2	R/BOUT COLUMN	4	$ 115.39	$ 95.99
HPS0170-ST-0620-002-B	2	SHARED OR NO POLE	1	$ 111.98	$ 93.15
HPS0170-ST-0660-002-B	2	SHARED OR NO POLE	2	$ 111.98	$ 93.15
HPS0170-ST-0770-002-B	2	WOOD POLE	2	$ 119.45	$ 99.37
HPS0170-ST-1030-002-B	2	SHARED OR NO POLE	2	$ 111.98	$ 93.15
HPS0170-ST-1080-002-B	2	WOOD POLE	1	$ 111.98	$ 93.15
HPS0170-ST-1130-002-B	2	STEEL POLE	2	$ 118.81	$ 98.83
HPS0170-ST-1170-002-B	2	STEEL POLE	1	$ 125.63	$ 104.51
HPS0170-TA-0600-002-B	2	R/BOUT COLUMN	4	$ 109.69	$ 91.25
HPS0180-ST-0870-002-B	2	R/BOUT COLUMN	4	$ 135.21	$ 112.48

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
HPS0190-ST-1470-002-B	2	R/BOUT COLUMN	1	$ 161.15	$ 134.05
HPS0250-ST-0120-002-B	2	SHARED OR NO POLE	1	$ 95.74	$ 79.64
HPS0250-ST-1050-002-B	2	R/BOUT COLUMN	4	$ 99.15	$ 82.48
INC0030-ST-0010-002-B	2	SHARED OR NO POLE	1	$ 26.99	$ 22.45
INC0030-ST-0810-002-B	2	WOOD POLE	1	$ 41.93	$ 34.88
INC0030-ST-0820-002-B	2	SHARED OR NO POLE	3	$ 26.99	$ 22.45
INC0030-ST-0990-002-B	2	STEEL POLE	1	$ 40.63	$ 33.80
INC0050-ST-0010-002-B	2	SHARED OR NO POLE	1	$ 26.99	$ 22.45
INC0050-ST-0810-002-B	2	WOOD POLE	1	$ 41.93	$ 34.88
INC0080-ST-0010-002-B	2	SHARED OR NO POLE	1	$ 24.02	$ 19.98
INC0090-ST-0010-002-B	2	SHARED OR NO POLE	1	$ 24.02	$ 19.98
INC0100-ST-0740-002-B	2	SHARED OR NO POLE	2	$ 24.02	$ 19.98
INC0110-ST-0010-002-B	2	SHARED OR NO POLE	1	$ 24.02	$ 19.98
INC0160-ST-0620-002-B	2	SHARED OR NO POLE	1	$ 22.28	$ 18.54
LPS0030-ST-0040-002-B	2	SHARED OR NO POLE	1	$ 81.73	$ 67.99
LPS0030-ST-0360-002-B	2	STEEL POLE	1	$ 95.38	$ 79.34
LPS0030-ST-0890-002-B	2	SHARED OR NO POLE	2	$ 81.73	$ 67.99
LPS0040-ST-0050-002-B	2	SHARED OR NO POLE	1	$ 84.26	$ 70.09
LPS0040-ST-0220-002-B	2	WOOD POLE	1	$ 99.20	$ 82.52

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
LPS0040-ST-0310-002-B	2	STEEL POLE	1	$ 97.91	$ 81.45
LPS0050-ST-0060-002-B	2	SHARED OR NO POLE	1	$ 87.01	$ 72.38
LPS0060-ST-0060-002-B	2	SHARED OR NO POLE	1	$ 120.35	$ 100.11
LPS0060-ST-0230-002-B	2	WOOD POLE	1	$ 135.29	$ 112.54
LPS0060-ST-0320-002-B	2	STEEL POLE	1	$ 134.00	$ 111.47
LPS0060-ST-0390-002-B	2	STEEL POLE	2	$ 127.17	$ 105.79
LPS0060-ST-0590-002-B	2	R/BOUT COLUMN	4	$ 123.76	$ 102.95
LPS0060-ST-0960-002-B	2	SHARED OR NO POLE	2	$ 120.35	$ 100.11
LPS0090-ST-0070-002-B	2	SHARED OR NO POLE	1	$ 120.35	$ 100.11
MHR0010-ST-0040-002-B	2	SHARED OR NO POLE	1	$ 67.10	$ 55.82
MHR0010-ST-0360-002-B	2	STEEL POLE	1	$ 80.75	$ 67.17
MHR0010-ST-0730-002-B	2	STEEL POLE	2	$ 73.92	$ 61.49
MHR0030-ST-0050-002-B	2	SHARED OR NO POLE	1	$ 84.61	$ 70.38
MHR0030-ST-0310-002-B	2	STEEL POLE	1	$ 98.25	$ 81.73
MHR0030-ST-0690-002-B	2	STEEL POLE	2	$ 91.43	$ 76.06
MHR0030-ST-0710-002-B	2	STEEL POLE	3	$ 89.16	$ 74.16
MHR0060-ST-0060-002-B	2	SHARED OR NO POLE	1	$ 89.16	$ 74.17
MHR0060-ST-0320-002-B	2	STEEL POLE	1	$ 102.80	$ 85.52
MHR0060-ST-0390-002-B	2	STEEL POLE	2	$ 95.98	$ 79.84

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
MHR0060-ST-0590-002-B	2	R/BOUT COLUMN	4	$ 92.57	$ 77.00
MHR0060-ST-0610-002-B	2	SHARED OR NO POLE	1	$ 89.16	$ 74.17
MHR0060-ST-0650-002-B	2	SHARED OR NO POLE	2	$ 89.16	$ 74.17
MHR0060-ST-1070-002-B	2	WOOD POLE	1	$ 104.10	$ 86.59
MHR0060-ST-1120-002-B	2	STEEL POLE	1	$ 102.80	$ 85.52
MHR0060-ST-1160-002-B	2	WOOD POLE	2	$ 96.63	$ 80.38
MHR0070-ST-0060-002-B	2	SHARED OR NO POLE	1	$ 89.49	$ 74.44
MHR0070-ST-0320-002-B	2	STEEL POLE	1	$ 103.14	$ 85.80
MHR0070-ST-0390-002-B	2	STEEL POLE	2	$ 96.32	$ 80.12
MHR0070-ST-0470-002-B	2	STEEL POLE	4	$ 92.90	$ 77.28
MHR0070-ST-0620-002-B	2	SHARED OR NO POLE	1	$ 89.49	$ 74.44
MHR0070-ST-0660-002-B	2	SHARED OR NO POLE	2	$ 89.49	$ 74.44
MHR0070-ST-1080-002-B	2	WOOD POLE	1	$ 89.49	$ 74.44
MHR0070-ST-1170-002-B	2	STEEL POLE	1	$ 103.14	$ 85.80
MHR0100-ST-0120-002-B	2	SHARED OR NO POLE	1	$ 95.53	$ 79.47
MVA0010-ST-0010-002-B	2	SHARED OR NO POLE	1	$ 51.02	$ 42.44
MVA0010-ST-0810-002-B	2	WOOD POLE	1	$ 65.96	$ 54.87
MVA0010-ST-0990-002-B	2	STEEL POLE	1	$ 64.67	$ 53.79
MVA0010-ST-1000-002-B	2	STEEL POLE	2	$ 57.84	$ 48.12

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
MVA0020-ST-0010-002-B	2	SHARED OR NO POLE	1	$ 51.02	$ 42.45
MVA0020-ST-0740-002-B	2	SHARED OR NO POLE	2	$ 51.02	$ 42.45
MVA0020-ST-0810-002-B	2	WOOD POLE	1	$ 65.97	$ 54.87
MVA0020-ST-0820-002-B	2	SHARED OR NO POLE	3	$ 51.02	$ 42.45
MVA0020-ST-0990-002-B	2	STEEL POLE	1	$ 64.67	$ 53.80
MVA0020-ST-1000-002-B	2	STEEL POLE	2	$ 57.85	$ 48.12
MVA0020-ST-1260-002-B	2	WOOD POLE	2	$ 58.49	$ 48.66
MVA0020-ST-1460-002-B	2	STEEL POLE	3	$ 55.57	$ 46.23
MVA0080-ST-0010-002-B	2	SHARED OR NO POLE	1	$ 48.86	$ 40.64
MVA0080-ST-0740-002-B	2	SHARED OR NO POLE	2	$ 48.86	$ 40.64
MVA0080-ST-0810-002-B	2	WOOD POLE	1	$ 63.80	$ 53.07
MVA0080-ST-0990-002-B	2	STEEL POLE	1	$ 62.51	$ 52.00
MVA0190-ST-0020-002-B	2	SHARED OR NO POLE	1	$ 62.48	$ 51.97
MVA0190-ST-0200-002-B	2	WOOD POLE	1	$ 77.42	$ 64.40
MVA0190-ST-0290-002-B	2	STEEL POLE	1	$ 76.13	$ 63.33
MVA0190-ST-0370-002-B	2	STEEL POLE	2	$ 69.30	$ 57.65
MVA0190-ST-0450-002-B	2	STEEL POLE	4	$ 65.89	$ 54.81
MVA0190-ST-0780-002-B	2	WOOD POLE	2	$ 69.95	$ 58.19
MVA0190-ST-0940-002-B	2	SHARED OR NO POLE	2	$ 62.48	$ 51.97

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
MVA0220-ST-0030-002-B	2	SHARED OR NO POLE	1	$ 74.24	$ 61.76
MVA0220-ST-0210-002-B	2	WOOD POLE	1	$ 89.18	$ 74.19
MVA0220-ST-0300-002-B	2	STEEL POLE	1	$ 87.89	$ 73.11
MVA0220-ST-0380-002-B	2	STEEL POLE	2	$ 81.06	$ 67.43
MVA0220-ST-0460-002-B	2	STEEL POLE	4	$ 77.65	$ 64.60
MVA0220-ST-0790-002-B	2	WOOD POLE	2	$ 81.71	$ 67.97
MVA0220-ST-0950-002-B	2	SHARED OR NO POLE	2	$ 74.24	$ 61.76
MVA0260-ST-0250-002-B	2	WOOD POLE	1	$ 121.98	$ 101.47
MVA0290-ST-1040-002-B	2	SHARED OR NO POLE	2	$ 145.70	$ 121.20
FLU0350-ST-1620-003-B	3	SHARED OR NO POLE	1	$ 104.17	$ 84.38
FLU0350-ST-1630-003-B	3	SHARED OR NO POLE	2	$ 118.94	$ 96.57
FLU0350-ST-1660-003-B	3	WOOD POLE	1	$ 207.63	$ 163.78
FLU0350-ST-1670-003-B	3	WOOD POLE	2	$ 214.94	$ 169.76
FLU0350-ST-1700-003-B	3	STEEL POLE	1	$ 277.48	$ 216.53
FLU0350-ST-1710-003-B	3	STEEL POLE	2	$ 285.43	$ 223.04
FLU0355-ST-1980-003-B	3	SHARED OR NO POLE	1	$ 108.56	$ 88.04
FLU0355-ST-2060-003-B	3	STEEL POLE	1	$ 281.87	$ 220.18
HPS0010-TA-0090-003-B	3	SHARED OR NO POLE	1	$ 119.40	$ 97.01
HPS0010-TA-0140-003-B	3	WOOD POLE	1	$ 222.87	$ 176.41

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
HPS0010-TA-0170-003-B	3	STEEL POLE	1	$ 292.71	$ 229.15
HPS0020-ST-0040-003-B	3	SHARED OR NO POLE	1	$ 120.48	$ 97.92
HPS0020-ST-0350-003-B	3	WOOD POLE	1	$ 223.94	$ 177.32
HPS0020-ST-0360-003-B	3	STEEL POLE	1	$ 293.79	$ 230.07
HPS0020-ST-0730-003-B	3	STEEL POLE	2	$ 306.14	$ 240.21
HPS0020-ST-0890-003-B	3	SHARED OR NO POLE	2	$ 139.65	$ 113.74
HPS0020-TA-0090-003-B	3	SHARED OR NO POLE	1	$ 121.57	$ 98.81
HPS0020-TA-0140-003-B	3	WOOD POLE	1	$ 225.03	$ 178.21
HPS0020-TA-0170-003-B	3	STEEL POLE	1	$ 294.88	$ 230.95
HPS0090-ST-0050-003-B	3	SHARED OR NO POLE	1	$ 184.80	$ 149.95
HPS0090-ST-0220-003-B	3	WOOD POLE	1	$ 288.26	$ 229.36
HPS0090-ST-0310-003-B	3	STEEL POLE	1	$ 339.67	$ 268.15
HPS0090-ST-0690-003-B	3	STEEL POLE	2	$ 364.03	$ 288.20
HPS0090-TA-0220-003-B	3	WOOD POLE	1	$ 279.32	$ 221.92
HPS0090-TA-0310-003-B	3	STEEL POLE	1	$ 330.73	$ 260.71
HPS0110-ST-0060-003-B	3	SHARED OR NO POLE	1	$ 186.67	$ 151.50
HPS0110-ST-0230-003-B	3	WOOD POLE	1	$ 290.13	$ 230.91
HPS0110-ST-0320-003-B	3	STEEL POLE	1	$ 341.54	$ 269.70
HPS0110-ST-0390-003-B	3	STEEL POLE	2	$ 366.23	$ 290.02

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
HPS0110-ST-0590-003-B	3	R/BOUT COLUMN	4	$ 547.70	$ 431.37
HPS0110-ST-0610-003-B	3	SHARED OR NO POLE	1	$ 199.61	$ 162.18
HPS0110-ST-0760-003-B	3	WOOD POLE	2	$ 314.17	$ 250.69
HPS0110-ST-0960-003-B	3	SHARED OR NO POLE	2	$ 218.18	$ 177.50
HPS0110-ST-1070-003-B	3	WOOD POLE	1	$ 303.07	$ 241.58
HPS0110-ST-1120-003-B	3	STEEL POLE	1	$ 354.48	$ 280.38
HPS0110-TA-0060-003-B	3	SHARED OR NO POLE	1	$ 176.57	$ 143.10
HPS0110-TA-0230-003-B	3	WOOD POLE	1	$ 280.03	$ 222.50
HPS0110-TA-0320-003-B	3	STEEL POLE	1	$ 331.44	$ 261.30
HPS0170-ST-0070-003-B	3	SHARED OR NO POLE	1	$ 200.31	$ 162.79
HPS0170-ST-0240-003-B	3	WOOD POLE	1	$ 303.77	$ 242.19
HPS0170-ST-0330-003-B	3	STEEL POLE	1	$ 355.18	$ 280.98
HPS0170-ST-0620-003-B	3	SHARED OR NO POLE	1	$ 196.92	$ 159.99
HPS0170-ST-1130-003-B	3	STEEL POLE	2	$ 408.75	$ 325.13
HPS0170-ST-1170-003-B	3	STEEL POLE	1	$ 364.97	$ 289.06
MHR0060-ST-0060-003-B	3	SHARED OR NO POLE	1	$ 168.18	$ 136.13
MHR0060-ST-0320-003-B	3	STEEL POLE	1	$ 323.06	$ 254.33
MHR0060-ST-0610-003-B	3	SHARED OR NO POLE	1	$ 181.13	$ 146.81
MHR0060-ST-1120-003-B	3	STEEL POLE	1	$ 336.00	$ 265.01

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
MHR0070-ST-0620-003-B	3	SHARED OR NO POLE	1	$ 174.43	$ 141.28
MVA0020-ST-0010-003-B	3	SHARED OR NO POLE	1	$ 96.14	$ 77.70
MVA0020-ST-0810-003-B	3	WOOD POLE	1	$ 199.61	$ 157.10
MVA0020-ST-0990-003-B	3	STEEL POLE	1	$ 269.45	$ 209.84
MVA0190-ST-0020-003-B	3	SHARED OR NO POLE	1	$ 142.43	$ 114.70
MVA0190-ST-0200-003-B	3	WOOD POLE	1	$ 245.90	$ 194.10
MVA0190-ST-0290-003-B	3	STEEL POLE	1	$ 297.30	$ 232.90
FLU0130-ST-0010-004-B	4	SHARED OR NO POLE	1	$ 42.21	$ 35.11
FLU0240-ST-0010-004-B	4	SHARED OR NO POLE	1	$ 47.07	$ 39.16
FLU0350-ST-1620-004-B	4	SHARED OR NO POLE	1	$ 60.31	$ 50.17
FLU0350-ST-1630-004-B	4	SHARED OR NO POLE	2	$ 60.31	$ 50.17
FLU0350-ST-1640-004-B	4	SHARED OR NO POLE	3	$ 60.31	$ 50.17
FLU0350-ST-1650-004-B	4	SHARED OR NO POLE	4	$ 60.31	$ 50.17
FLU0350-ST-1660-004-B	4	WOOD POLE	1	$ 75.25	$ 62.60
FLU0350-ST-1670-004-B	4	WOOD POLE	2	$ 67.78	$ 56.39
FLU0350-ST-1700-004-B	4	STEEL POLE	1	$ 73.96	$ 61.53
FLU0350-ST-1710-004-B	4	STEEL POLE	2	$ 67.14	$ 55.85
FLU0350-ST-1720-004-B	4	STEEL POLE	3	$ 64.86	$ 53.96
FLU0350-ST-1730-004-B	4	STEEL POLE	4	$ 63.73	$ 53.01

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
FLU0355-ST-1980-004-B	4	SHARED OR NO POLE	1	$ 64.74	$ 53.86
FLU0355-ST-2060-004-B	4	STEEL POLE	1	$ 78.39	$ 65.21
HPS0010-TA-0090-004-B	4	SHARED OR NO POLE	1	$ 68.40	$ 56.90
HPS0010-TA-0140-004-B	4	WOOD POLE	1	$ 83.34	$ 69.33
HPS0010-TA-0170-004-B	4	STEEL POLE	1	$ 82.05	$ 68.25
HPS0020-ST-0040-004-B	4	SHARED OR NO POLE	1	$ 72.23	$ 60.08
HPS0020-ST-0350-004-B	4	WOOD POLE	1	$ 87.17	$ 72.51
HPS0020-ST-0360-004-B	4	STEEL POLE	1	$ 85.87	$ 71.44
HPS0020-ST-0730-004-B	4	STEEL POLE	2	$ 79.05	$ 65.76
HPS0020-ST-0880-004-B	4	STEEL POLE	4	$ 75.64	$ 62.92
HPS0020-ST-0890-004-B	4	SHARED OR NO POLE	2	$ 72.23	$ 60.08
HPS0020-ST-0910-004-B	4	WOOD POLE	2	$ 79.70	$ 66.30
HPS0020-TA-0090-004-B	4	SHARED OR NO POLE	1	$ 70.56	$ 58.70
HPS0020-TA-0140-004-B	4	WOOD POLE	1	$ 85.50	$ 71.13
HPS0020-TA-0170-004-B	4	STEEL POLE	1	$ 84.21	$ 70.05
HPS0090-ST-0050-004-B	4	SHARED OR NO POLE	1	$ 106.10	$ 88.26
HPS0090-ST-0220-004-B	4	WOOD POLE	1	$ 121.04	$ 100.69
HPS0090-ST-0310-004-B	4	STEEL POLE	1	$ 119.75	$ 99.61
HPS0090-ST-0690-004-B	4	STEEL POLE	2	$ 112.92	$ 93.93

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
HPS0090-ST-0710-004-B	4	STEEL POLE	3	$ 110.65	$ 92.04
HPS0090-ST-0720-004-B	4	STEEL POLE	4	$ 109.51	$ 91.10
HPS0090-ST-0980-004-B	4	WOOD POLE	2	$ 113.57	$ 94.47
HPS0090-ST-1010-004-B	4	SHARED OR NO POLE	2	$ 106.10	$ 88.26
HPS0090-ST-1360-004-B	4	R/BOUT COLUMN	3	$ 110.65	$ 92.04
HPS0090-TA-0050-004-B	4	SHARED OR NO POLE	1	$ 97.16	$ 80.82
HPS0090-TA-0310-004-B	4	STEEL POLE	1	$ 110.81	$ 92.18
HPS0110-ST-0060-004-B	4	SHARED OR NO POLE	1	$ 107.64	$ 89.54
HPS0110-ST-0230-004-B	4	WOOD POLE	1	$ 122.58	$ 101.97
HPS0110-ST-0320-004-B	4	STEEL POLE	1	$ 121.28	$ 100.89
HPS0110-ST-0390-004-B	4	STEEL POLE	2	$ 114.46	$ 95.22
HPS0110-ST-0430-004-B	4	STEEL POLE	3	$ 112.19	$ 93.32
HPS0110-ST-0470-004-B	4	STEEL POLE	4	$ 111.05	$ 92.38
HPS0110-ST-0550-004-B	4	R/BOUT COLUMN	3	$ 112.19	$ 93.32
HPS0110-ST-0590-004-B	4	R/BOUT COLUMN	4	$ 111.05	$ 92.38
HPS0110-ST-0610-004-B	4	SHARED OR NO POLE	1	$ 107.64	$ 89.54
HPS0110-ST-0650-004-B	4	SHARED OR NO POLE	2	$ 107.64	$ 89.54
HPS0110-ST-0760-004-B	4	WOOD POLE	2	$ 115.11	$ 95.75
HPS0110-ST-0960-004-B	4	SHARED OR NO POLE	2	$ 107.64	$ 89.54

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
HPS0110-ST-0970-004-B	4	SHARED OR NO POLE	4	$ 107.64	$ 89.54
HPS0110-ST-1070-004-B	4	WOOD POLE	1	$ 122.58	$ 101.97
HPS0110-ST-1120-004-B	4	STEEL POLE	1	$ 121.28	$ 100.89
HPS0110-ST-1160-004-B	4	WOOD POLE	2	$ 115.11	$ 95.75
HPS0110-ST-1380-004-B	4	R/BOUT COLUMN	3	$ 112.19	$ 93.32
HPS0110-ST-1450-004-B	4	R/BOUT COLUMN	4	$ 111.05	$ 92.38
HPS0110-TA-0060-004-B	4	SHARED OR NO POLE	1	$ 97.54	$ 81.14
HPS0110-TA-0230-004-B	4	WOOD POLE	1	$ 112.48	$ 93.57
HPS0110-TA-0320-004-B	4	STEEL POLE	1	$ 111.18	$ 92.49
HPS0110-TA-0590-004-B	4	R/BOUT COLUMN	4	$ 100.95	$ 83.98
HPS0120-ST-0860-004-B	4	R/BOUT COLUMN	3	$ 128.15	$ 106.60
HPS0170-ST-0070-004-B	4	SHARED OR NO POLE	1	$ 111.98	$ 93.15
HPS0170-ST-0240-004-B	4	WOOD POLE	1	$ 126.92	$ 105.58
HPS0170-ST-0270-004-B	4	R/BOUT COLUMN	3	$ 116.53	$ 96.94
HPS0170-ST-0330-004-B	4	STEEL POLE	1	$ 125.63	$ 104.51
HPS0170-ST-0400-004-B	4	STEEL POLE	2	$ 118.81	$ 98.83
HPS0170-ST-0440-004-B	4	STEEL POLE	3	$ 116.53	$ 96.94
HPS0170-ST-0480-004-B	4	STEEL POLE	4	$ 115.39	$ 95.99
HPS0170-ST-0560-004-B	4	R/BOUT COLUMN	3	$ 116.53	$ 96.94

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
HPS0170-ST-0600-004-B	4	R/BOUT COLUMN	4	$ 115.39	$ 95.99
HPS0170-ST-0620-004-B	4	SHARED OR NO POLE	1	$ 111.98	$ 93.15
HPS0170-ST-0660-004-B	4	SHARED OR NO POLE	2	$ 111.98	$ 93.15
HPS0170-ST-0900-004-B	4	WOOD POLE	2	$ 119.45	$ 99.37
HPS0170-ST-1030-004-B	4	SHARED OR NO POLE	2	$ 111.98	$ 93.15
HPS0170-ST-1130-004-B	4	STEEL POLE	2	$ 118.81	$ 98.83
HPS0170-ST-1170-004-B	4	STEEL POLE	1	$ 125.63	$ 104.51
HPS0190-ST-1470-004-B	4	R/BOUT COLUMN	1	$ 161.15	$ 134.05
HPS0250-ST-1050-004-B	4	R/BOUT COLUMN	4	$ 99.15	$ 82.48
MHR0010-ST-0040-004-B	4	SHARED OR NO POLE	1	$ 67.10	$ 55.82
MHR0010-ST-0360-004-B	4	STEEL POLE	1	$ 80.75	$ 67.17
MHR0060-ST-0060-004-B	4	SHARED OR NO POLE	1	$ 89.16	$ 74.17
MHR0060-ST-0320-004-B	4	STEEL POLE	1	$ 102.80	$ 85.52
MHR0060-ST-0390-004-B	4	STEEL POLE	2	$ 95.98	$ 79.84
MHR0060-ST-0610-004-B	4	SHARED OR NO POLE	1	$ 89.16	$ 74.17
MHR0070-ST-0060-004-B	4	SHARED OR NO POLE	1	$ 89.49	$ 74.44
MHR0070-ST-0320-004-B	4	STEEL POLE	1	$ 103.14	$ 85.80
MHR0070-ST-0620-004-B	4	SHARED OR NO POLE	1	$ 89.49	$ 74.44
MHR0070-ST-1170-004-B	4	STEEL POLE	1	$ 103.14	$ 85.80

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
MHR0100-ST-0120-004-B	4	SHARED OR NO POLE	1	$ 95.53	$ 79.47
MVA0010-ST-0010-004-B	4	SHARED OR NO POLE	1	$ 51.02	$ 42.44
MVA0010-ST-0990-004-B	4	STEEL POLE	1	$ 64.67	$ 53.79
MVA0020-ST-0010-004-B	4	SHARED OR NO POLE	1	$ 51.02	$ 42.45
MVA0020-ST-0740-004-B	4	SHARED OR NO POLE	2	$ 51.02	$ 42.45
MVA0020-ST-0810-004-B	4	WOOD POLE	1	$ 65.97	$ 54.87
MVA0020-ST-0990-004-B	4	STEEL POLE	1	$ 64.67	$ 53.80
MVA0020-ST-1000-004-B	4	STEEL POLE	2	$ 57.85	$ 48.12
MVA0190-ST-0020-004-B	4	SHARED OR NO POLE	1	$ 62.48	$ 51.97
MVA0190-ST-0200-004-B	4	WOOD POLE	1	$ 77.42	$ 64.40
MVA0190-ST-0290-004-B	4	STEEL POLE	1	$ 76.13	$ 63.33
MVA0190-ST-0570-004-B	4	R/BOUT COLUMN	4	$ 65.89	$ 54.81
MVA0220-ST-0030-004-B	4	SHARED OR NO POLE	1	$ 74.24	$ 61.76
MVA0220-ST-0210-004-B	4	WOOD POLE	1	$ 89.18	$ 74.19
FLU0350-ST-1620-005-B	5	SHARED OR NO POLE	1	$ 154.13	$ 135.03
HPS0010-ST-0040-005-B	5	SHARED OR NO POLE	1	$ 161.31	$ 142.63
HPS0010-ST-0360-005-B	5	STEEL POLE	1	$ 334.69	$ 277.36
HPS0020-ST-0040-005-B	5	SHARED OR NO POLE	1	$ 164.46	$ 145.84
HPS0020-ST-0350-005-B	5	WOOD POLE	1	$ 293.63	$ 247.45

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
HPS0020-ST-0360-005-B	5	STEEL POLE	1	$ 337.85	$ 280.57
HPS0020-ST-0730-005-B	5	STEEL POLE	2	$ 365.81	$ 301.54
HPS0020-ST-0750-005-B	5	SHARED OR NO POLE	3	$ 234.04	$ 201.66
HPS0020-ST-0890-005-B	5	SHARED OR NO POLE	2	$ 199.25	$ 173.75
HPS0020-ST-0910-005-B	5	WOOD POLE	2	$ 320.95	$ 267.76
HPS0070-ST-0040-005-B	5	SHARED OR NO POLE	1	$ 164.46	$ 145.84
HPS0090-ST-0050-005-B	5	SHARED OR NO POLE	1	$ 228.01	$ 203.32
HPS0090-ST-0220-005-B	5	WOOD POLE	1	$ 357.18	$ 304.93
HPS0090-ST-0310-005-B	5	STEEL POLE	1	$ 380.29	$ 322.07
HPS0090-ST-0690-005-B	5	STEEL POLE	2	$ 416.82	$ 350.12
HPS0090-ST-0710-005-B	5	STEEL POLE	3	$ 457.91	$ 382.79
HPS0090-ST-0980-005-B	5	WOOD POLE	2	$ 393.07	$ 332.31
HPS0090-ST-1010-005-B	5	SHARED OR NO POLE	2	$ 271.37	$ 238.30
HPS0090-ST-1360-005-B	5	R/BOUT COLUMN	3	$ 581.50	$ 476.29
HPS0090-TA-0050-005-B	5	SHARED OR NO POLE	1	$ 219.07	$ 194.23
HPS0090-TA-0220-005-B	5	WOOD POLE	1	$ 348.24	$ 295.84
HPS0090-TA-0310-005-B	5	STEEL POLE	1	$ 371.35	$ 312.99
HPS0090-TA-0690-005-B	5	STEEL POLE	2	$ 407.88	$ 341.03
HPS0090-TA-1010-005-B	5	SHARED OR NO POLE	2	$ 262.43	$ 229.21

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
HPS0090-TA-1370-005-B	5	R/BOUT COLUMN	4	$ 614.79	$ 501.03
HPS0100-ST-0230-005-B	5	WOOD POLE	1	$ 354.25	$ 301.92
HPS0100-ST-0430-005-B	5	STEEL POLE	3	$ 455.28	$ 380.02
HPS0110-ST-0060-005-B	5	SHARED OR NO POLE	1	$ 229.70	$ 205.01
HPS0110-ST-0230-005-B	5	WOOD POLE	1	$ 358.87	$ 306.62
HPS0110-ST-0320-005-B	5	STEEL POLE	1	$ 381.98	$ 323.76
HPS0110-ST-0390-005-B	5	STEEL POLE	2	$ 418.66	$ 351.93
HPS0110-ST-0470-005-B	5	STEEL POLE	4	$ 502.27	$ 418.67
HPS0110-ST-0550-005-B	5	R/BOUT COLUMN	3	$ 583.49	$ 478.23
HPS0110-ST-0590-005-B	5	R/BOUT COLUMN	4	$ 625.87	$ 512.17
HPS0110-ST-0760-005-B	5	WOOD POLE	2	$ 394.91	$ 334.12
HPS0110-ST-0930-005-B	5	WOOD POLE	3	$ 435.93	$ 366.70
HPS0110-ST-0960-005-B	5	SHARED OR NO POLE	2	$ 273.21	$ 240.11
HPS0110-TA-0060-005-B	5	SHARED OR NO POLE	1	$ 219.60	$ 194.74
HPS0110-TA-0230-005-B	5	WOOD POLE	1	$ 348.77	$ 296.35
HPS0110-TA-0320-005-B	5	STEEL POLE	1	$ 371.88	$ 313.49
HPS0110-TA-0390-005-B	5	STEEL POLE	2	$ 408.56	$ 341.66
HPS0110-TA-0590-005-B	5	R/BOUT COLUMN	4	$ 615.77	$ 501.90
HPS0110-TA-0960-005-B	5	SHARED OR NO POLE	2	$ 263.11	$ 229.84

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
HPS0140-ST-0070-005-B	5	SHARED OR NO POLE	1	$ 235.34	$ 208.77
HPS0140-ST-0330-005-B	5	STEEL POLE	1	$ 387.61	$ 327.52
HPS0140-ST-0400-005-B	5	STEEL POLE	2	$ 434.55	$ 364.15
HPS0140-ST-1030-005-B	5	SHARED OR NO POLE	2	$ 289.10	$ 252.33
HPS0160-ST-0070-005-B	5	SHARED OR NO POLE	1	$ 244.01	$ 217.59
HPS0160-ST-0240-005-B	5	WOOD POLE	1	$ 373.17	$ 319.19
HPS0160-ST-0330-005-B	5	STEEL POLE	1	$ 396.28	$ 336.34
HPS0160-ST-0770-005-B	5	WOOD POLE	2	$ 419.46	$ 355.16
HPS0170-ST-0070-005-B	5	SHARED OR NO POLE	1	$ 244.30	$ 217.88
HPS0170-ST-0240-005-B	5	WOOD POLE	1	$ 373.46	$ 319.49
HPS0170-ST-0330-005-B	5	STEEL POLE	1	$ 396.57	$ 336.64
HPS0170-ST-0400-005-B	5	STEEL POLE	2	$ 443.51	$ 373.26
HPS0170-ST-0600-005-B	5	R/BOUT COLUMN	4	$ 671.22	$ 550.42
HPS0170-ST-0770-005-B	5	WOOD POLE	2	$ 419.76	$ 355.46
HPS0170-ST-1030-005-B	5	SHARED OR NO POLE	2	$ 298.06	$ 261.45
HPS0170-TA-0070-005-B	5	SHARED OR NO POLE	1	$ 238.60	$ 212.08
HPS0170-TA-0240-005-B	5	WOOD POLE	1	$ 367.76	$ 313.69
HPS0170-TA-0330-005-B	5	STEEL POLE	1	$ 390.87	$ 330.84
HPS0170-TA-0400-005-B	5	STEEL POLE	2	$ 437.81	$ 367.46

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
HPS0170-TA-0600-005-B	5	R/BOUT COLUMN	4	$ 665.52	$ 544.62
LPS0030-ST-0040-005-B	5	SHARED OR NO POLE	1	$ 173.97	$ 155.50
LPS0030-ST-0350-005-B	5	WOOD POLE	1	$ 303.13	$ 257.11
LPS0030-ST-0360-005-B	5	STEEL POLE	1	$ 347.35	$ 290.23
LPS0030-ST-0890-005-B	5	SHARED OR NO POLE	2	$ 208.76	$ 183.41
LPS0040-ST-0050-005-B	5	SHARED OR NO POLE	1	$ 206.18	$ 181.12
LPS0040-ST-0220-005-B	5	WOOD POLE	1	$ 335.34	$ 282.73
LPS0040-ST-0310-005-B	5	STEEL POLE	1	$ 358.45	$ 299.87
LPS0050-ST-0060-005-B	5	SHARED OR NO POLE	1	$ 209.08	$ 184.04
LPS0050-ST-0230-005-B	5	WOOD POLE	1	$ 338.24	$ 285.64
LPS0050-ST-0320-005-B	5	STEEL POLE	1	$ 361.35	$ 302.79
LPS0060-ST-0060-005-B	5	SHARED OR NO POLE	1	$ 242.42	$ 217.94
MHR0060-ST-0060-005-B	5	SHARED OR NO POLE	1	$ 211.22	$ 186.22
MHR0060-ST-0320-005-B	5	STEEL POLE	1	$ 363.50	$ 304.97
MHR0070-ST-0060-005-B	5	SHARED OR NO POLE	1	$ 211.56	$ 186.56
MHR0070-ST-0320-005-B	5	STEEL POLE	1	$ 363.83	$ 305.31
FLU0350-ST-1620-005-B	5	SHARED OR NO POLE	1	$ 154.13	$ 135.03
HPS0020-ST-0040-005-B	5	SHARED OR NO POLE	1	$ 164.46	$ 145.84
HPS0020-ST-0350-005-B	5	WOOD POLE	1	$ 293.63	$ 247.45

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights		SLUOS charge
HPS0020-ST-0360-005-B	5	STEEL POLE	1	$ 337.85	$ 280.57
HPS0020-ST-0730-005-B	5	STEEL POLE	2	$ 365.81	$ 301.54
HPS0020-ST-0890-005-B	5	SHARED OR NO POLE	2	$ 199.25	$ 173.75
HPS0090-ST-0050-005-B	5	SHARED OR NO POLE	1	$ 228.01	$ 203.32
HPS0090-ST-0220-005-B	5	WOOD POLE	1	$ 357.18	$ 304.93
HPS0090-ST-0310-005-B	5	STEEL POLE	1	$ 380.29	$ 322.07
HPS0090-ST-0690-005-B	5	STEEL POLE	2	$ 416.82	$ 350.12
HPS0090-TA-0220-005-B	5	WOOD POLE	1	$ 348.24	$ 295.84
HPS0090-TA-0310-005-B	5	STEEL POLE	1	$ 371.35	$ 312.99
HPS0110-ST-0060-005-B	5	SHARED OR NO POLE	1	$ 229.70	$ 205.01
HPS0110-ST-0230-005-B	5	WOOD POLE	1	$ 358.87	$ 306.62
HPS0110-ST-0320-005-B	5	STEEL POLE	1	$ 381.98	$ 323.76
HPS0110-ST-0390-005-B	5	STEEL POLE	2	$ 418.66	$ 351.93
HPS0110-ST-0590-005-B	5	R/BOUT COLUMN	4	$ 625.87	$ 512.17
HPS0110-ST-0760-005-B	5	WOOD POLE	2	$ 394.91	$ 334.12
HPS0110-ST-0960-005-B	5	SHARED OR NO POLE	2	$ 273.21	$ 240.11
HPS0110-TA-0060-005-B	5	SHARED OR NO POLE	1	$ 219.60	$ 194.74
HPS0110-TA-0230-005-B	5	WOOD POLE	1	$ 348.77	$ 296.35
HPS0110-TA-0320-005-B	5	STEEL POLE	1	$ 371.88	$ 313.49

ANNUALTARIFF_ID	Tariff Type	Dedicated Support Type	No. of Lights	SLUOS charge	
HPS0170-ST-0070-005-B	5	SHARED OR NO POLE	1	$ 244.30	$ 217.88
HPS0170-ST-0240-005-B	5	WOOD POLE	1	$ 373.46	$ 319.49
HPS0170-ST-0330-005-B	5	STEEL POLE	1	$ 396.57	$ 336.64
MHR0060-ST-0060-005-B	5	SHARED OR NO POLE	1	$ 211.22	$ 186.22
MHR0060-ST-0320-005-B	5	STEEL POLE	1	$ 363.50	$ 304.97
MVA0190-ST-0290-005-B	5	STEEL POLE	1	$ 342.68	$ 282.69

A.3 Metering

Table 16.28 Annual metering charge – Final decision ($ nominal)

Tariff class	Costs	2015/16	2016/17	2017/18	2018/19
Existing customers					
Residential anytime	Non–capital	22.33	23.17	24.04	24.95
	Capital	9.26	9.61	9.97	10.34
Residential TOU	Non–capital	30.67	31.83	33.03	34.27
	Capital	9.26	9.61	9.97	10.34
Small business anytime	Non–capital	22.33	23.17	24.04	24.95
	Capital	9.26	9.61	9.97	10.34

Small business TOU	Non–capital	30.67	31.83	33.03	34.27
	Capital	9.26	9.61	9.97	10.34
Controlled load	Non–capital	6.74	6.99	7.26	7.53
	Capital	4.22	4.37	4.54	4.71
Solar (Gross meter only)	Non–capital	30.18	31.31	32.50	33.72
	Capital	8.45	8.77	9.10	9.44
New customers					
Anytime customers	Non–capital	14.83	15.39	15.97	16.58
	Capital	0.00	0.00	0.00	0.00
TOU customers	Non–capital	19.77	20.51	21.29	22.09
	Capital	0.00	0.00	0.00	0.00
Controlled load	Non–capital	4.73	4.91	5.09	5.28
	Capital	0.00	0.00	0.00	0.00
Solar additions	Non–capital	19.33	20.06	20.82	21.60
	Capital	0.00	0.00	0.00	0.00

Source: AER analysis

Note: Prices for 2016–17 to 2018–19 are indicative only and will be adjusted for actual CPI during the AER's annual pricing approval processes.

Table 16.29 AER final decision X factors for annual metering charges (per cent)

	2016–17	2017–18	2018–19
X factor	–1.36	–1.36	–1.36

Source: AER analysis

Table 16.30 Upfront capital charges – Final decision

Meter	Upfront capital charge ($2014–15)
Single Phase Accumulation	35.10
Three Phase Accumulation	132.60
Single Phase TOU	97.69
Single Phase 2 element (TOU)	229.74
Three Phase TOU	321.70
Three Phase CT	458.04

Source: AER analysis

Table 16.31 AER final decision X factors for upfront capital charge (per cent)

	2015–16	2016–17	2017–18	2018–19
X factor	0.0	0.0	0.0	0.0

Source: AER analysis